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BEFORE THE ARIZONA CORPORATION COMMISSION

DOCKETED

NOV 30 1998

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COMMISSIONER  
CARL J. KUNASEK  
COMMISSIONER

DOCKETED BY

*sd*

IN THE MATTER OF THE  
APPLICATION OF TUCSON ELECTRIC  
POWER COMPANY FOR APPROVAL  
OF ITS STRANDED COST RECOVERY.

DOCKET NO. E-01933A-98-0471

IN THE MATTER OF THE FILING OF  
TUCSON ELECTRIC POWER  
COMPANY OF UNBUNDLED TARIFFS  
PURSUANT TO A.A.C. R14-2-1601 et seq.

DOCKET NO. E-01933A-97-0772

IN THE MATTER OF THE APPLICATION  
APPLICATION OF ARIZONA PUBLIC  
SERVICE COMPANY FOR APPROVAL  
OF ITS STRANDED COST RECOVERY.

DOCKET NO. E-01345A-98-0473

IN THE MATTER OF THE FILING OF  
ARIZONA PUBLIC SERVICE  
COMPANY OF UNBUNDLED TARIFFS  
PURSUANT TO A.A.C. R14-2-1601 et seq.

DOCKET NO. E-01345A-97-0773

IN THE MATTER OF COMPETITION IN  
THE PROVISION OF ELECTRIC  
SERVICES THROUGHOUT THE STATE  
OF ARIZONA.

DOCKET NO. RE-00000C-94-0165

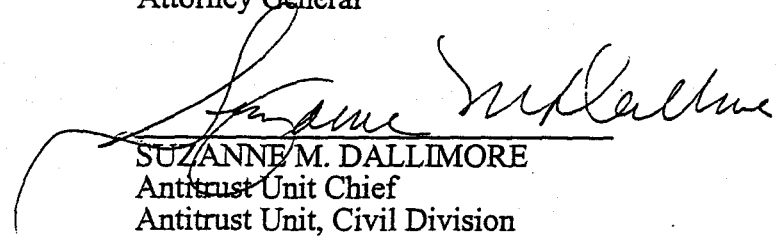
NOTICE OF FILING OF EXHIBITS TO DIRECT TESTIMONY OF  
MARK W. FRANKENA, Ph.D.

The Attorney General, a party in the above-captioned consolidated docket acting on behalf of the citizens of the State of Arizona and pursuant to Rule R14-3-109(Q) of the Arizona Corporation Commission rules of procedure, hereby files the original and ten (10) copies of the exhibits to the direct testimony of Mark W. Frankena, Ph.D., filed earlier today, November 30,

1 1998, on the matter of the proposed Settlement Agreement between the Staff of the Arizona  
2 Corporation Commission and Tucson Electric Power Company and Arizona Public Service  
3 Company. Copies of the exhibits to the testimony will be mailed to the attached Service List or  
4 can be obtained by hand-delivery.

5  
6 RESPECTFULLY SUBMITTED this 30th day of November, 1998.

7 GRANT WOODS  
8 Attorney General

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**AN ORIGINAL AND TEN COPIES**  
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Docket Control  
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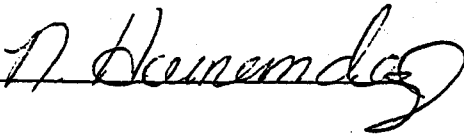
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Deputy Director for Economic Policy Analysis  
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Economic Advisor to the Chairman (1986)  
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**Testimony**

Affidavit on behalf of Barrick and Newmont gold mines concerning remedies for Sierra Pacific Power's market power, Public Service Commission of Nevada, Docket No. 97-8001, May 15, 1998.

Prepared testimony on behalf of WPS Resources and Upper Peninsula Energy concerning competitive effects of their merger, Federal Energy Regulatory Commission, Docket EC98-27, Jan. 23, 1998. The Commission approved the merger as proposed, 83 FERC ¶61, 196.

Affidavit on behalf of the Maine Attorney General on New England Power Pool's proposal for detection and mitigation of market power, Federal Energy Regulatory Commission, Docket Nos. OA97-237 and ER97-1079, Jan. 23, 1998.

Affidavits on behalf of LG&E Energy affiliates providing hub-and-spoke analyses in support of applications for market-based pricing, Federal Energy Regulatory Commission, Docket Nos: ER98-\_\_\_\_- and ER98-\_\_\_\_-, Dec. 31, 1997.

Prepared testimony on behalf of UtiliCorp United concerning competitive effects of the merger of Western Resources and Kansas City Power & Light, Federal Energy Regulatory Commission, Docket No. EC 97-56, Nov. 17, 1997.

Prepared testimony on behalf of LG&E and Kentucky Utilities providing an analysis of their merger using the methodology specified by Appendix A of FERC's Merger Policy Statement, Federal Energy Regulatory

**Testimony  
(cont.)**

Commission, Docket No. EC98-2, Oct. 9, 1997. Cited in Commission order approving merger as proposed, 82 FERC ¶61,308.

Affidavit on behalf of the City of Austin concerning competitive effects of the merger of PG&E Corporation and Valero Energy, Federal Energy Regulatory Commission, Docket No. EC97-22, May 23, 1997..

Prepared testimony on behalf of Commission Staff concerning market power of Sierra Pacific Power and Nevada Power in a restructured electric industry, Public Service Commission of Nevada, Docket No. 95-9022, January 31, 1997.

Testimony, surrebuttal testimony and cross-examination on behalf of Madison Gas & Electric, Citizens' Utility Board, the Wisconsin Electric Cooperative Association, and the Wisconsin Industrial Energy Group concerning competitive effects of the merger of Northern States Power and Wisconsin Electric Power, Public Service Commission of Wisconsin, Docket No. 6630-UM-100/4420-UM-101, Oct. 8, Oct. 30, and Nov. 5, 1996.

Testimony and cross-examination on behalf of Madison Gas & Electric, Minnesota Power, Otter Tail Power and Lincoln Electric System concerning competitive effects of the merger of Northern States Power and Wisconsin Electric Power, Federal Energy Regulatory Commission, Docket EC95-16, May 10 and June 11, 1996. Cited in Commission order rejecting merger as proposed, 79 FERC ¶61,158.

Affidavit on market definition, *Caribbean Broadcasting System, Ltd., et al., v. Cable and Wireless P.L.C., et al.*, U.S. District Court, January 31, 1994.

Affidavit on behalf of Occidental Chemical Corp. concerning competitive effects of the acquisition of Gulf States Utilities by Entergy, Federal Energy Regulatory Commission, Docket EC92-21, September 28, 1992.

**Testimony  
(cont.)**

Testimony and cross-examination on behalf of Public Service of New Hampshire concerning competitive effects of the acquisition of PSNH by Northeast Utilities, U.S. Bankruptcy Court, November 1989.

**Add'l Electric  
and Gas  
Experience**

Damage estimation for breach of contract suit by a steam host against a QF.

Market power analysis of monopolization suit by QF against an investor-owned utility.

Competitive analysis of PECO Energy's proposed acquisition of Pennsylvania Power and Light on behalf of the latter.

Competitive analysis of Southern California Edison's proposed merger with San Diego Gas & Electric for Federal Energy Regulatory Commission and California Public Utilities Commission proceedings on behalf of the City of San Diego.

Evaluation of competition issues in merger of American Electric Power and Central and South West on behalf of latter.

Competitive analysis of mergers between Public Service of New Mexico and Gas Company of New Mexico, Duke Power and PanEnergy, and other electric and gas companies.

Competitive analysis of gas pipeline mergers between MidCon and United Energy Resources, and between InterNorth and Houston Natural Gas.

Reports on market power in electric power markets in Spain on behalf of the Spanish National Electric Regulatory Commission and in New York on behalf of an energy services company.

**Add'l Electric  
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Experience (cont.)**

Competitive analysis of the proposed merger of four Dutch electric generating companies on behalf of the Dutch Competition Authority.

Review of study of competitive effects of synchronous interconnection of ERCOT and the SPP on behalf of Public Utility Commission of Texas staff.

**Invited Pre-  
sentations on  
Analysis of  
Market Power  
in the Electric  
and Gas  
Industries**

American Bar Association,  
Annual Meeting, August 1997  
Electricity Conference, February 1998  
Annual Meeting, mock trial witness, August 1998  
Federal Energy Bar Association,  
Meeting, November 1997  
U.S. Department of Justice and Federal Trade  
Commission, Conference, April 1996  
Federal Trade Commission, Bureau of Economics  
Retreat, December 1997  
Federal Energy Regulatory Commission,  
Staff Seminar, September 1997  
Edison Electric Institute, Economics Committee,  
May 1996  
National Association of Regulatory Utility Commissioners,  
NARUC/DOE Electricity Forum, December 1997  
Conference, March 1998  
Spanish National Electric Regulatory Commission,  
December 1996, February 1997  
Electricity Consumers Resource Council (ELCON),  
Annual Seminar, October 1996  
Institute of Public Utilities,  
Conference, November 1996

**Experience  
with Other  
Industries**

Mass Media and Advertising

Competitive analyses of cable network mergers:  
CNBC/FNN financial news networks on behalf of NBC;  
HSN/QVC home shopping networks on behalf of TCI.

Cable television antitrust suit by Viacom against TCI on behalf of the latter.

**Experience  
with Other  
Industries  
(cont.)**

Children's television programming antitrust suit by Buena Vista against Fox on behalf of the latter.

Online database antitrust suit by Dialog against American Chemical Society on behalf of former.

Federal Communications Commission rulemakings on station ownership and financial interest and syndication rules on behalf of ABC, CBS, and NBC.

Competition between cable television and direct-broadcast satellites on behalf of National Cable Television Association.

Telecommunications

Deceptive advertising litigation between MCI and AT&T on behalf of former.

Federal Communications Commission rulemakings on cellular telephony and personal communications services on behalf of AT&T Wireless.

Market power analysis and damage estimate for satellite communications monopolization suit by PanAmSat against Comsat.

Competitive analysis of a merger of two regional Bell operating companies on behalf of a ratepayer group.

Manufacturing

Competitive analyses of mergers and joint ventures involving power transformers and other heavy electric equipment, small electric motors, petroleum refining, oilfield and refinery chemicals, automobiles, specialty vehicles, sheets and towels, soft drinks, hair coloring products and numerous other manufacturing and service industries.

## **Publications**

### **Antitrust (1985 - Present)**

*Antitrust Policy for Declining Industries*, with P. Pautler, FTC Bureau of Economics, 1985, 108 pages.

"FERC's Acceptance of Market-Based Pricing: An Antitrust Analysis," with Barry C. Harris, *The Electricity Journal*, June 1992, pp. 38-51.

"Competitive Issues in Electric Utility Mergers," with Bruce M. Owen, *International Merger Law*, October 1992.

"Antitrust Analysis of Electric Utility Mergers after the Energy Policy Act," with Bruce M. Owen, *International Merger Law*, February 1993.

"Flawed Reasoning," with Bruce M. Owen, *Public Utilities Fortnightly*, July 15, 1993, pp. 25-27. (On FERC's decision not to investigate competitive effects of the Entergy/GSU merger.)

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B

# **ADDRESSING MARKET POWER**

## **THE NEXT STEP IN ELECTRIC RESTRUCTURING**

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## CONTENTS

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1	Introduction .....	1
2	Findings and Executive Summary .....	5
3	Developments in the Electric Power Industry .....	15
4	What is Market Power? .....	19
5	Market Power in the Electric Power Industry .....	25
6	Assessing Market Power .....	35
7	Dealing with Market Power .....	47
8	Mergers and Market Power .....	57
9	Retail Customer Choice and Market Power .....	67
10	Market Power and Federal Legislation .....	75

### Appendices

A	Sources and Bibliography .....	81
B	The Evasion of Regulation .....	85

## 4

## WHAT IS MARKET POWER?

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As background for the discussion of market power in the electric industry, this chapter introduces the economic principles of competition and market power. This introduction explains how competitive markets benefit consumers, the nature of market power, and why market power matters.

### CONSUMER BENEFITS FROM COMPETITIVE MARKETS

In a competitive market, sellers take market prices as given and expand production and sales as long as the cost of producing and delivering an additional unit is less than the market price. Sellers behave in this way because they cannot profitably raise the market price by reducing the output they supply. A market is likely to be competitive if there are many sellers or if entry of new sellers is easy.

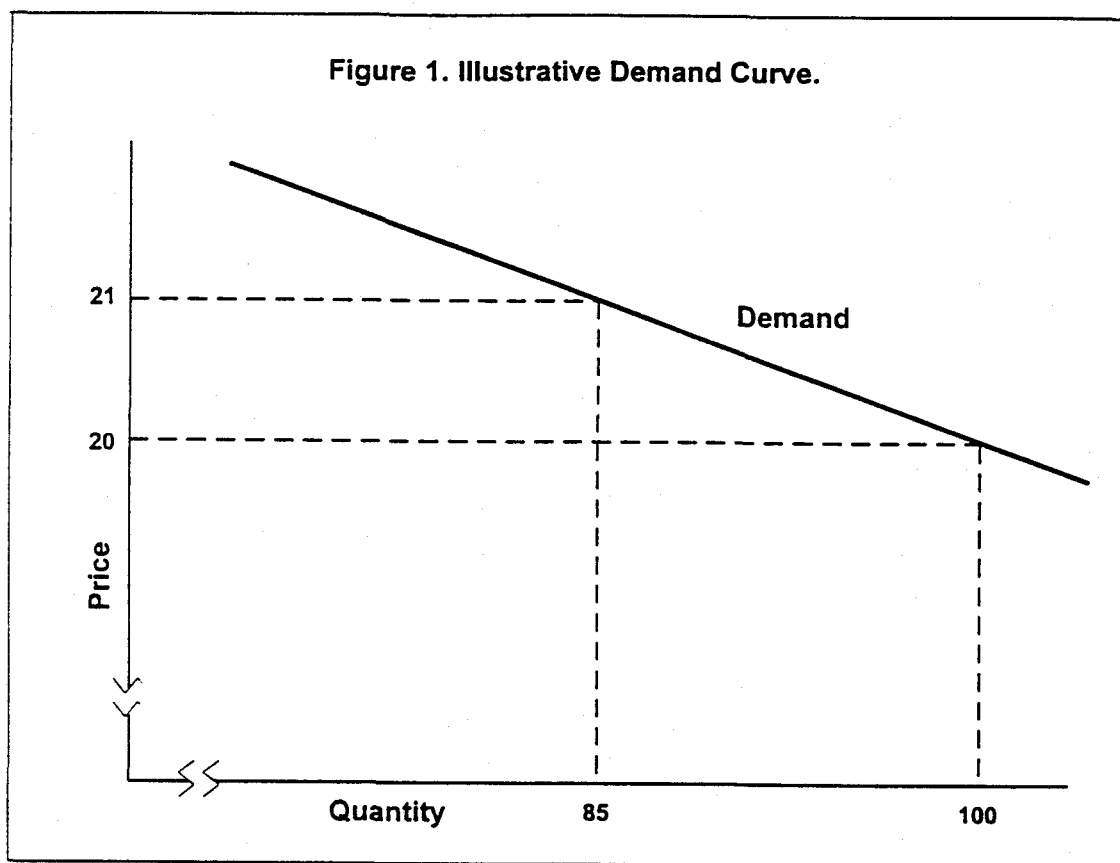
In the United States, there is a public policy preference for competitive markets. Competitive markets generally lead to an efficient allocation of resources and the highest possible level of economic well being for society as a whole. The “invisible hand” of the market leads sellers who are pursuing profits to be responsive to consumers and to supply the goods and services that have the greatest value to them, given limited resources. Prices, profits and losses provide sellers with appropriate incentives to enter or exit markets, expand or contract capacity, and increase or reduce output in response to continuing changes in consumer preferences and incomes, technology, and resource costs. The benefits to consumers from competitive markets provide the rationale for restructuring the electric power industry and deregulating segments of the industry that are, or that can be made, competitive.

While competitive markets have many virtues, there are situations in which society may not prefer unfettered competitive markets. This may be the case when activities have effects outside markets as they are traditionally defined. For example, competitive markets may not maximize consumer economic well being without government intervention when activities have serious environmental effects. Adverse environmental effects may be brought within the market through appropriate assignment of property rights, such as rights to air quality. Absent action to induce companies to take environmental effects into account, companies in an industry that causes pollution are likely to produce each unit of output in a manner that causes too much pollution and, under competition, to produce too many units of output.

## MARKET POWER DEFINED AND ILLUSTRATED

The key feature of competitive markets is that sellers cannot profitably raise prices by reducing the amounts they supply. Market power is defined as the ability of one or more sellers profitably to raise prices above competitive levels for a significant period of time. A market is not competitive when sellers have market power.

The first step in understanding market power is to recognize that a supplier will sell fewer units of output if it charges a higher price, because some buyers will decide to do without the product or switch to substitutes. The demand for a supplier's output can be represented by a Demand curve, such as the one in Figure 1. Referring to the graph in Figure 1, we see that, if the seller offers its output at a price of \$20 per unit, it will sell 100 units; at a price of \$21, it will sell 85 units.



This example assumes that the seller starts by quoting a price. However, one could also think of the same seller as starting by delivering some number of units of output to the market and selling them for the highest price at which all would be

purchased. In Figure 1, if the seller delivered 100 units of output to the market, the seller could obtain \$20 per unit. If the seller instead delivered only 85 units to the market, the price would be \$21.

To determine whether a seller has market power, one can perform the following experiment. Start with the level of output the seller would supply if it behaved competitively. Now suppose the seller began to reduce its output. If it could reduce output to zero without bringing about an increase in the market price, clearly the seller has no market power; this would be the case if the Demand curve were horizontal.

Now suppose a seller faces a demand curve like the curve in Figure 1. In this case, if the seller reduced its output, the market price would increase. But this fact alone is not sufficient to demonstrate that the seller has market power. To conclude that the seller has market power, one must determine that the effort to raise the market price would *increase the seller's profits*. And this depends on whether the profit on sales of fewer units at the higher price exceeds the profit on sales of more units at the lower price.

We can make that calculation in this example. Referring again to Figure 1, suppose the seller would sell 100 units at a price of \$20 per unit if the seller behaved competitively. Let's assume that the cost of producing each of these units is \$16. To raise the market price by one dollar to \$21, the seller would have to reduce its output to 85 units. In this case, the seller would earn an additional \$85 on the output it would continue to sell, that is, an extra dollar on each of 85 units. However, it would forego profits of \$60 on the output that it would no longer sell, that is, a \$4 profit (the competitive price of \$20 minus the unit cost of \$16) on each of 15 units. Thus, the net effect of the price increase and the output reduction would be to increase the seller's profits by \$25, i.e., \$85 minus \$60.

In this hypothetical example, the seller can *profitably* raise prices above competitive levels, and therefore the seller has market power. However, if the demand curve in the hypothetical were changed so that the seller had to reduce its output to 75 (rather than 85) in order to raise the price by \$1, the seller acting alone would not have market power. In this case, the seller's profits would decline by \$25 if it tried to raise the market price by withholding twenty-five units, and hence the seller would not have an incentive to raise prices. One conclusion that can be drawn from this discussion is that the existence of market power depends on several factors, including the cost structure of the seller and the demand curve of the buyers.

In order to analyze market power correctly, it is important to understand that companies cannot simply insist upon high prices by virtue of being big. The quantity of a product purchased by consumers depends on the price. Therefore, a company that charges a higher price will sell fewer units of output and may earn lower profits.

In sum, a firm with a large market share that attempts to raise the price of a product may find it profitable to take one of the two following actions, which are equivalent:

- Reduce its output (below the competitive level) in order to raise the price (above the competitive level).
- Raise its price (above the competitive level), even though this involves a reduction in sales (below the competitive level).

If a firm finds such actions profitable, we say it has *market power*.

### UNILATERAL MARKET POWER AND COLLUSION

Market power may be exercised by a single company or by two or more companies acting simultaneously. Companies may exercise market power simultaneously without an agreement to limit competition, or they may reach an agreement to *collude*. Collusion is *tacit* if the agreement is reached without overt communication or sharing of profits. A colluding company forgoes profitable opportunities to increase sales because it understands that, if it were to cheat on the agreement, other colluding companies would punish it by taking steps that would lower its profits.

The following hypothetical illustrates how tacit collusion could operate in a market for electric energy during some hours of the year. Suppose that Utility A and Utility B each have a 500 megawatt (MW) generator with variable costs of \$25 per megawatt-hour (MWh), as well as other generators with lower variable costs. Assume that these two 500 MW generators are the only units in the market with variable costs between \$25/MWh and \$28/MWh.

Even without overt communication, Utility A and Utility B could arrive at a mutually profitable understanding that each would withhold the output of these generators from the market until the market price reached \$27.95/MWh. The result of such a tacit agreement would be that, during hours in which these 500 MW generators would be the marginal (highest variable cost) units operating in the market, the market price would be nearly 12% above the competitive level of \$25/MWh.

It is worth repeating that this understanding does not require an explicit agreement. If Utility A was a slow learner, or cheated on the understanding, and produced energy from its 500 MW generator when the market price was, say, only \$27/MWh, Utility B could teach Utility A a lesson by running its own 500 MW generator at an even lower price, reducing Utility A's profits. Utility A would

quickly conclude that it would achieve higher profits by withholding supply. Acting in this way, Utilities A and B would be tacitly colluding to exercise market power.

## WHY MARKET POWER MATTERS

When an electric generating company exercises market power, buyers pay higher prices for electric power. Consumption patterns are distorted — too little electric power is consumed. In addition, costs of generation are increased for society because some efficient generating units belonging to the company exercising market power are not used while less efficient units owned by others are used instead. Also, companies that do not face vigorous competition are apt to be less vigilant about cutting costs and to have lower productivity. Such companies are also less responsive to consumers.

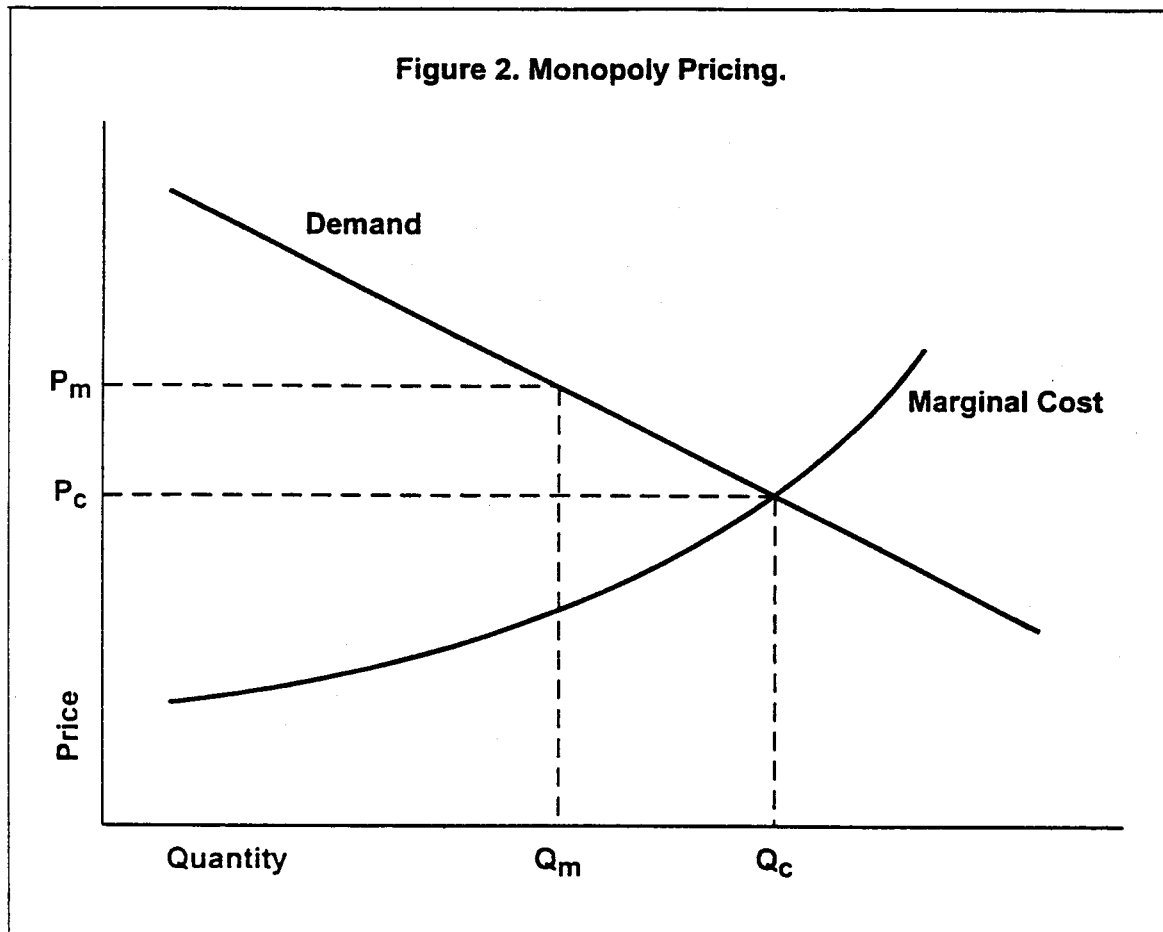
### When Firms Have and Exercise Market Power

- Prices are too high
- Consumption is distorted
- Firms have lower productivity
- Firms are less responsive to consumers

Market power in the electric power industry is a critical public policy issue because of the role of the industry in the economy. The electricity sector is the nation's most capital intensive industry; the book value of capital investment was nearly \$700 billion in 1994. Retail expenditures on electricity amount to \$212 billion annually in the United States. (DOE 1998) Purchases of electricity are a major budget item for consumers, businesses, government and others. As a result, market power injures consumers who pay higher electric bills, higher prices for goods and services produced using electricity, and higher taxes to pay for government services.

Figure 2 illustrates the problem of monopoly pricing. The height of the Demand line at any output level expresses how much consumers are willing to pay for an additional unit of service. The height of the Marginal Cost curve represents the incremental cost of producing an additional unit. If the industry were competitive, the price would equal  $P_c$  and output would equal  $Q_c$ . That is, the price would equal the incremental cost of the last unit of output produced. Because no consumer would be willing to pay enough for another unit of service to cover its costs, the "right" output is produced.

In contrast, a monopolist charges a price of  $P_m$  and produces an output of  $Q_m$ . The units of service between  $Q_m$  and  $Q_c$  are not produced by the monopolist even though the amount that consumers are willing to pay for each of these units (the height of the Demand line) is greater than the incremental cost of supplying them (the height of the Marginal Cost curve). In short, the monopolist does not produce enough output and charges too high a price.



Electric restructuring should lead to lower costs, better customer service, and lower average prices for electric power. However, the extent of these benefits depends on whether restructuring programs produce competitive markets or tolerate market power.

Electricity prices — and therefore the benefits that are anticipated from electric restructuring — depend importantly on whether restructured markets for electric power are competitive. Consequently, it is critical for legislators, regulators and antitrust authorities to evaluate market power using sound methodologies. While the basic principles of market power analysis apply to all industries, the application of these principles depends on the individual characteristics of an industry. This chapter discusses characteristics of the electric power industry that make market power analyses complex, and then addresses ways in which market power may be exercised in the electric power supply industry.

### **WHAT MAKES ELECTRIC POWER MARKETS COMPLEX?**

Assessment of competitive conditions in markets for electric power is complicated by a number of characteristics of the industry (Frankena 1996):

- Competitive conditions — including the geographic scope of competition, which types of generating units can compete, and price levels — differ substantially across seasons of the year and hours of the day. As a result, an accurate assessment of market power typically requires separate analyses for several representative periods during the year.
- Electric power is a network industry in which some activities have natural monopoly characteristics and other activities have competitive characteristics. In today's electric power industry, there are substantial amounts of common ownership between these vertically related monopoly and competitive activities.
- Networks that are used to transmit electric power have unique properties. Unlike the telephone network, the electric transmission grid is not a "switched" network; energy cannot be directed from a generator to a buyer along a particular path. Instead, energy flows along multiple paths without regard to ownership or contracts. Also, the capacity of the grid to transmit energy is subject to constraints imposed by system reliability requirements. Attempts to define and measure transmission capacity and to regulate its availability to third parties face great difficulties. In addition, some generating units must operate to maintain voltages on the transmission system to ensure system reliability.
- The ability and incentives of vertically integrated utilities to raise wholesale prices during a "transition" period lasting for at least several years will depend

on the details of state restructuring programs. The effects of higher wholesale prices on a utility's profits will depend on the timing and extent of retail customer choice, provisions for retail rate reductions and freezes, and mechanisms adopted for recovery of stranded costs.

These complicating characteristics of the electric power industry help to explain why methodologies used to assess market power in the industry are constantly being improved.

## HOW MARKET POWER MAY BE EXERCISED IN ELECTRIC POWER MARKETS

In this section we describe the variety of incentives and opportunities electric utilities may have to act in an anticompetitive manner. The purpose of this exploration is not to indict the industry, but rather to suggest the range of market power problems with which legislators, regulators and antitrust authorities must grapple.

### Horizontal Market Power

For expository purposes, it is useful to begin the discussion of how market power may be exercised with the assumption that companies in the electric power supply industry are not vertically integrated. (Issues that arise because of vertical integration will be considered below.)

Absent vertical integration, the companies involved at each step of production and delivery — fuel supply, generation, transmission, distribution, and marketing — would be independent. In such an industry, a company would generally exercise any market power it might have by reducing its output below the competitive level (or raising its offer prices above the competitive level) in order to bring about an increase in the market price. The term *horizontal market power* refers to this way of exercising market power.

Of the various stages of production and distribution of electric power, generation receives the greatest attention in assessments of horizontal market power. The Federal Energy Regulatory Commission (FERC) focuses heavily on horizontal market power in generation — also called *generation market power* — in evaluating applications for market-based pricing and for approval of mergers. Generation market power is exercised when a company that owns generating plants brings about an increase in market prices for electric power by reducing the output of its generators or — equivalently — by raising the prices at which it offers to supply wholesale power.

When a company reduces the output of its generators, market prices will increase until other companies with higher-cost generators find it profitable to supply

additional output to replace output withheld by the company exercising market power, or until buyers sufficiently reduce their consumption. A company may achieve the same result by raising the prices at which it offers power — for example, the prices it bids into a power pool. If a company raises its prices, it will sell less, and market prices will increase until other suppliers (with higher costs) find it profitable to supply additional output to replace the power no longer being supplied by the company exercising market power.

Recall that a firm will withhold output in this manner only if doing so increases its profits. The underlying condition for generation market power is this: a company that owns a large share of the generating capacity in a market may have an incentive to reduce the amount it sells in order to raise the prices at which it sells its remaining output.

While evaluation of horizontal market power in generation often receives careful attention in restructuring proceedings and merger evaluations, it is now typical for regulators simply to assume that transmission and distribution companies are natural monopolies and hence have horizontal market power. It is also typical to assume that, absent vertical integration, an adequate way to deal with horizontal market power in transmission and distribution is to regulate prices for wires services. This current approach to horizontal market power represents a change from several years ago. At that time, generation market power was largely ignored and attention was focused on the effects of electric utility mergers — such as the abandoned merger of Southern California Edison (SoCal Edison) and San Diego Gas & Electric (SDG&E) — on competition in transmission (Frankena and Owen 1994, Chap. 4).

A different issue of horizontal market power is raised by mergers between electric and gas distribution utilities with overlapping retail territories, and also when an electric distribution utility proposes to merge with a gas pipeline that can influence the price of gas sold to customers of the electric company. Electricity and natural gas compete for some uses, such as space heating and cooling, water heating, and cooking. By reducing competition between electricity and gas, electric-gas mergers may increase horizontal market power over energy, defined broadly to include both electricity and natural gas (*Id.*, pp. 130-33).

## Vertical Market Power

A number of additional potential market power problems arise when a company operates at two or more stages — fuel supply, generation, transmission, distribution, and marketing — in the production and delivery of electric power. These additional problems are termed *vertical market power* because they involve two or more stages in the supply chain. For expository purposes, vertical market power will be discussed in the context of a parent company that owns subsidiaries

that are engaged in different stages of production and delivery. (Other organizational forms, such as unified companies operating at more than one stage, as well as joint ventures, can also give rise to concerns about vertical market power. However, the essential issues can be illustrated with the parent/subsidiaries model used here.)

Vertical market power can arise when one subsidiary has a monopoly (usually a regulated monopoly) at one stage and a second subsidiary is engaged in a competitive (usually unregulated) activity at another stage. Three vertical combinations that may raise concerns are shown in Table 1.

Table 1. Vertical Combinations that May Raise Competitive Problems.	
Monopoly Activity	Related Competitive Activity
Electric transmission	Generation, wholesale marketing
Electric distribution	Retail marketing
Natural gas pipelines, coal mines	Electric Generation

These and some other vertical combinations raises concerns about several interrelated forms of potential affiliate abuses, particular the following:

- Discrimination in access to monopoly facilities.
- Other actions to raise costs and reduce availability of inputs used by non-affiliated competitors.
- Improper information sharing.
- Cross-subsidization and self-dealing.

Such abuses may increase market power or the extent to which market power is exercised, in addition to raising other concerns. Some abuses may enable the company to bring about price increases in potentially competitive markets by raising rivals' costs and foreclosing competition. Cross-subsidization and self-dealing raise market power concerns because a firm engaging in such behavior may thereby evade regulations intended to prevent anticompetitive pricing for the monopolized activity, distorting conditions in two markets.

We begin the discussion of market power problems raised by vertical combinations by focusing on discrimination and other actions that adversely affect the price and non-price terms on which inputs are available to competitors. Following this discussion, we examine improper information sharing, cross-subsidization and self-dealing.

## Transmission Market Power

When a company owns both (i) generating plants in a market and (ii) transmission facilities required by competitors to reach that market, the company may have an incentive to withhold transmission service from competitors in order to raise the prices at which the output of its generators can be sold. In effect, the company may be able to use its control over transmission to raise its rivals' costs or to exclude them from the market.

*Transmission market power* is exercised when a company that owns both generating plants and transmission facilities brings about an increase in the market prices at which it sells electric power by reducing the availability of transmission service required by competing generators to reach the market. Transmission market power need not involve ownership of generating plants: a similar problem may arise when a company owns both a wholesale marketer and transmission facilities.

One method of exercising transmission market power is a simple denial of transmission service needed by competing generators to reach a market. In light of FERC's open access requirements for transmission, utilities must, of course, have an explanation for denials, such as their own requirements for transmission capacity to serve native loads or to maintain reliability.

More subtle methods of exercising transmission market power include:

(i) restricting the transfer capability of the transmission system by selectively limiting investments in facilities or failing to dispatch generators that supply reactive power; (ii) reducing the reliability of transmission service, for example, by calling for line loading relief that interrupts competitors' deliveries; and (iii) refusing to discount prices of transmission service when circumstances would warrant this. When a transmission system owner that was not vertically integrated might offer discounts to enable a power producer to reach a market, a vertically integrated company might refuse to discount prices, effectively raising prices for transmission service.

## Distribution Market Power

A company that has a monopoly over distribution (wires) services and also offers retail supply and energy services is likely to have an incentive to discriminate against non-affiliated marketing companies (or retail customers that purchase from competing companies) in supplying wires services. Regulation is likely to constrain the prices that a distribution company can charge for wires services. Such regulation leaves a distribution company with an incentive to exercise its market power through discriminatory behavior: it can more fully exploit its distribution monopoly if it can force or induce retail customers to purchase power and energy

services from it at inflated prices. This potential problem will be referred to as *distribution market power*.

It is sometimes suggested that a distribution company may impede sales by non-affiliated marketers in ways that are more subtle than expressly denying service to competitors or tying its wire services and power and energy services. Such obvious tactics would, of course, likely run afoul of antitrust laws and regulations when competition is permitted. More subtly, a distribution company might provide superior regulated wires and backup services — for example, more reliable equipment, faster hookups, faster repairs, fewer service curtailments — to industrial customers that also purchase power or other energy services from the distribution company or its affiliates.

### Fuel Supply Market Power

When a company owns both (i) generating plants in a market and (ii) fuel supplies used by competing generators, or pipelines used to deliver natural gas to competing generators, then the company may have an incentive to raise the prices of inputs delivered to its competitors. The resulting increase in costs may reduce the ability of these other generators to compete, with the effect that electric power prices are increased. In short, the company may be able to use its control over fuel supplies or delivery to raise its rivals' costs or to exclude them from the market (Frankena 1997b). This form of market power will be referred to as *fuel supply market power*.

In addition to the potential problems described as transmission, distribution, and fuel-supply market power, the vertical combinations described in Table 1 may also lead to abuses related to improper information sharing, cross-subsidization and self-dealing. These are discussed next.

### Improper Information Sharing

In the normal course of business, a transmission company, a distribution company or a natural gas pipeline will typically obtain information that is valuable to companies engaged in competitive activities. For example, the profitability of entry by new generators or power marketers may depend in part on the availability of market information that a distribution company would collect. When the information is not confidential, a distribution company that is not vertically integrated would have an incentive to market such information. By contrast, a company that is engaged in both regulated and competitive activities may have an incentive to keep such information from non-affiliated companies — for example, new generators or marketers. Even when the information is confidential and cannot be sold, a regulated company may still have an incentive improperly to share the information with its affiliates.

Regulatory requirements for the handling of such information may be only partially effective in alleviating this problem. For example, if a vertically integrated distribution company is obligated to provide affiliates and nonaffiliates with equal information, it may then have an incentive to impede entry of nonaffiliates by not disclosing such information at all. As the incumbent in the competitive market, it may gain from withholding such information to raise entry barriers.

Here are two examples of potential anticompetitive use of information:

- A distribution company may have detailed information about loads in its service territory that would reduce costs of location selection and risks for new generators. Similarly, a distribution company may have detailed information about specific customers that would reduce costs and risks for energy services companies. A distribution company that is affiliated with a generation or marketing subsidiary would have an incentive to withhold even non-confidential information from entrants with which it is not affiliated.
- If consumers can choose among suppliers of power, the distribution company will obtain information about competitors' sales each time customers change their suppliers of power. The distribution company may also obtain information on the characteristics of the power supplied, including load profiles and interruptions. This information could allow the distribution company or its affiliates to target their retail marketing of power, and to engage in price discrimination among retail customers, in ways that other competitors could not.

### **Evasion of Regulation**

Vertical integration between monopoly activities that are subject to cost-based regulation, on the one hand, and deregulated competitive activities, on the other, may permit a regulated company to evade regulation and increase the exercise of market power in the monopoly activity. A vertically integrated company may have incentives to cross-subsidize its competitive activities by underpricing goods and services supplied by the monopoly units to the competitive affiliates, and overpricing goods and services supplied by the competitive units to the monopoly affiliates. Such abuses would lead to inefficient prices and to transfers of monopoly profits to the unregulated units of the company. Ultimately, these abuses can lead to foreclosure of sales by more efficient competitors in the competitive activities, while raising prices of the monopoly activities.

**Cross-Subsidization.** Regulation of prices in the electric power industry is intended to constrain the exercise of market power. But cost-based regulation typically permits an increase in regulated prices when costs increase. The combination of cost-based regulation and an affiliation between monopoly and competitive enterprises gives rise to incentives to cross-subsidize competitive activities. Such a combination may allow the monopoly firm to evade the regulatory constraint on its exercise of market power. For example, by inappropriately allocating costs of nonregulated competitive activities to the regulated activity, the firm may obtain regulatory approval for an increase in cost-based prices for the latter, and thereby earn monopoly profits. Furthermore, cross-subsidization of competitive activities may cause more efficient rivals to be displaced. (See insert.)

A serious cross-subsidization problem can arise even *"when a regulated utility acquires a firm that is not vertically related. The use of common facilities and managers may create an insoluble cost allocation problem and provide the opportunity to charge utility customers for non-utility costs, consequently distorting resource allocation in the adjacent as well as the regulated market."* (DOJ 1984, n.35.)

As one illustration of the problem of cross-subsidization, consider the situation of a distribution utility that enters into various competitive activities. When a competitive activity succeeds, the distribution utility would have an incentive to spin it off to an unregulated affiliate at less than its market value. When the competitive activity fails, the distribution utility would have an incentive to allocate the costs to ratepayers. Such behavior would improperly shift both costs and risks to the monopoly customers and would be possible only because the firm does not face competition in the monopoly enterprise.

**Under and Overpricing in Affiliate Transactions.** Market power problems relating to underpricing of monopolized goods and services supplied to competitive affiliates of the company, as well as overpricing of goods and services supplied by competitive affiliates to monopoly units, may arise when (i) activities with market power are subject to cost-of-service regulation and (ii) revenues and costs for the activities with market power are computed using affiliate transactions prices that differ from market prices.

When they purchase from their unregulated affiliates, regulated monopoly companies have an incentive to pay their affiliates prices that exceed market prices. For example, a distribution utility with captive retail customers may have an incentive to inflate the prices at which electric power is purchased from a power marketing affiliate. The distribution company may then be able to increase the regulated prices at which it sells to captive customers to recover the inflated prices paid to the affiliate. If so, the distribution company will exercise market power, and

the resulting monopoly profits will appear as income for its affiliate. As a second example, a regulated transmission system operator may have an incentive to pay inflated prices for ancillary services, such as voltage control, purchased from affiliated generating plants.

Similarly, when they sell to their unregulated affiliates, regulated monopoly companies have an incentive to charge their affiliates prices below the market prices of the goods and services in question. For example, regulated monopolies have an incentive to give brand names, customer lists and other market and customer information to their unregulated affiliates free of charge.

Problems also arise in connection with non-price terms of transactions. For example, a regulated monopoly buyer may refrain from enforcing terms in a contract with an unregulated affiliate even though the same buyer would enforce such terms in a contract with a company that is not affiliated.

Regulation can seek to prevent such abuses by careful consideration of cost allocation methods and careful auditing of transactions between monopoly companies and their unregulated competitive affiliates. However, such regulation is costly and time-consuming. And, as a practical matter, regulators have strictly limited resources and cannot be expected to detect many attempts to evade regulation in this way.

## DO ELECTRIC COMPANIES EXERCISE MARKET POWER?

Market power is a genuine problem in important parts of the United States electric power supply industry, in part because of the market structures that society has inherited from the past era of regulated vertically integrated utilities shielded from competition. Transmission constraints and costs narrowly limit the geographic scope of competition for electric power in a number of areas of the country. Where relevant geographic markets are narrow, ownership of generating capacity is likely to be highly concentrated in the hands of incumbent utilities. Entry barriers for new generators are often substantial, particularly where there is excess capacity. When high concentration in ownership of generating capacity and entry barriers are combined, generation market power is likely. In addition, various forms of vertical market power are important problems because of vertical integration into potentially competitive activities by firms with monopoly power in transmission and distribution.

Market power abuses in electric power markets are not hypothetical. For example, since its 1990 restructuring, the electric power industry in England and Wales has been plagued by anticompetitive conduct by two generating companies, National Power and PowerGen, according to numerous reports (Kwoka 1997). The market power of these companies has been based on high shares of generating capacity, the

limited amounts of coal-fired generating capacity in the hands of competitors, control of generating units that must run to maintain the reliability of the electric system, and transmission constraints.

Also, there are well-known examples of self-dealing by vertically integrated companies in the electric power and other regulated industries. Such problems led to the breakup of AT&T in the early 1980s, to disallowances for SoCal Edison in the late 1980s, and to customer refunds by NYNEX in the 1990s (see Appendix B).

## CONCLUSION

Assessments of market power in the electric power industry are challenging both because of the unusual characteristics of the industry and because of the range of ways in which market power may be exercised. The next chapter of this report provides an explanation of methods used to assess market power in the industry, with particular attention to generation market power.

## 6

## ASSESSING MARKET POWER

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Assessing market power in the electric industry is complicated for several reasons, including the inherent characteristics of electric power, the legacy of vertical integration, inherited forms of regulation and the many changes occurring in the industry. Nonetheless, the basic framework that is appropriate to analyze market power in electric power is the same as that used in other industries.

This chapter begins with a discussion of how generation market power is assessed using traditional antitrust principles. Next, we discuss the contributions that simulation models can make to evaluation of generation market power. Finally, we address principles for assessing other types of market power, such as transmission and fuel supply market power.

To analyze horizontal market power using traditional antitrust principles, one identifies the products in a market and the geographic scope of that market. Next, one computes market shares and concentration and evaluates conditions for entry into the market. Finally, based on market shares, concentration, entry barriers and additional information about competitive conditions, one makes inferences about the likelihood that prices would exceed competitive levels.

### IDENTIFYING RELEVANT MARKETS

Before one can measure market shares and concentration, one must identify the scope of the market. Suppose the issue at hand is to assess the extent that any market power may affect market-determined prices for electric power in Wyoming. One of the electric power products sold in Wyoming is megawatt hours of electric energy delivered during summer off-peak hours (nights and weekends). To define the market that is appropriate for a market power analysis relating to this product, one must determine whether the pricing of this product is so constrained by competition with other products that those other products should be included in the same market.

#### Steps in Assessing Horizontal Market Power

- Identify relevant product and geographic markets
- Measure levels of concentration in markets
- Evaluate the difficulty of entry by competitors into markets
- Conclude whether prices are likely to exceed competitive levels

We begin the analysis with a thought experiment. Suppose one company owned all the generating facilities that could be used to supply summer off-peak electric energy. Would that company be able profitably to raise the price of this energy significantly (say, by 5%) above the competitive level for a significant period of time? If so, summer off-peak electric energy would be a relevant product market for a market power analysis. On the other hand, if the company could not profitably raise the price of that energy because many buyers would switch to natural gas, then the relevant product market would include not only summer off-peak electric energy but also natural gas.

As a matter of fact, analyses of consumer behavior demonstrate that no other products sufficiently constrain the pricing of summer off-peak electric energy, and hence summer off-peak electric energy is a relevant product market for assessment of market power. Similarly, electric energy delivered during each of the other major periods of the year (for example, winter peak hours) is a separate relevant product market.

This distinction among product markets during different time periods is important because competitive conditions in energy markets may vary over time. For example, in many regions of the United States, dispatchable gas-fired generating units cannot supply energy at the relatively low prices that prevail under competitive conditions during off-peak hours, and hence these generating units are not included in computing off-peak market shares. By contrast, efficient gas-fired generating units are included in markets for on-peak energy.

In addition to product markets for electric energy, there are markets for certain other electric power products as well. In regions where utilities have obligations to maintain generating capacity reserves, there are markets for generating capacity rights. Also, there may be markets for ancillary services supplied by generators, such as voltage control and spinning reserves.

### Geographic Scope of Markets

We now continue with our Wyoming hypothetical. Once relevant product markets have been defined, the next issue is the geographic scope of competition. Would a company that owned all the generating facilities in Wyoming that are able to produce and deliver energy at a competitive price during summer off-peak hours be able to raise prices significantly (say, by 5%) above the competitive level? If yes, only generators located in Wyoming are in the relevant geographic market.

Suppose, on the other hand, that this company could not profitably raise the price of that energy because many buyers would switch to energy generated in Montana. In this case, the relevant geographic market would include not only generators located in Wyoming but also those in Montana. To complicate matters further, the relevant

geographic markets for energy in which generators in Wyoming compete may vary among time periods. While the markets might include states to the north of Wyoming during the summer, they might include states to the south of Wyoming during the winter.

Determining the scope of geographic markets is the most difficult and contentious issue in assessing market power in the electric power industry. FERC's 1996 *Merger Policy Statement* (FERC 1996) adopted the U.S. Department of Justice and Federal Trade Commission *Merger Guidelines* (DOJ/FTC 1992) as the appropriate methodology for use in analyzing the effects of mergers on market power.<sup>1</sup>

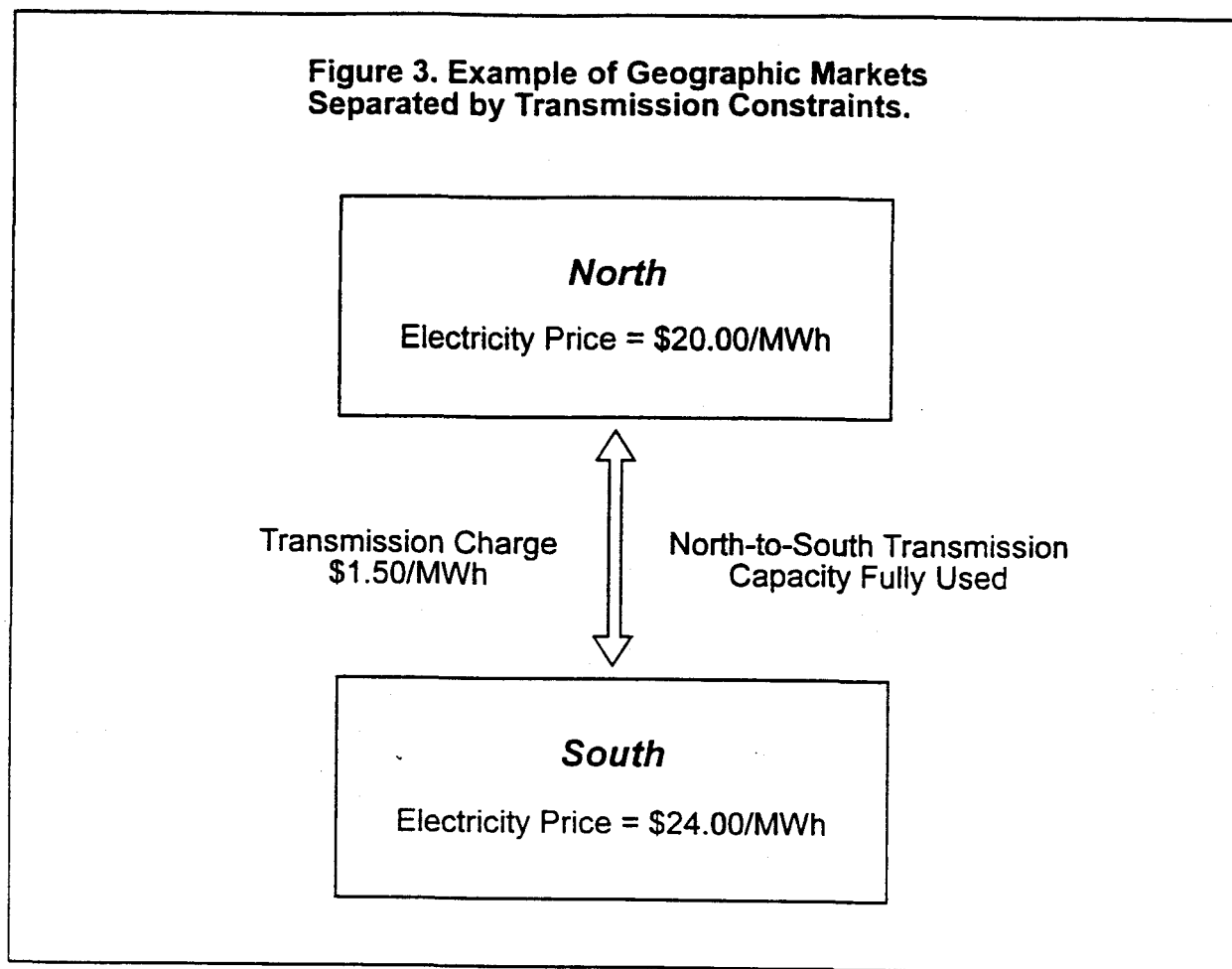
Identification of geographic markets for electric energy is difficult because competition depends on numerous factors in the pertinent region. These factors include: (i) capacities and variable costs of generating units; (ii) demands for energy by end-users; (iii) contractual and legal obligations of generators that limit the amounts of energy they can sell at market prices; (iv) transmission charges; (v) limits on transfer capabilities of the transmission system; and (vi) utility practices and regulations regarding access to the transmission system. Because the geographic scope of competition depends on so many factors, economists are beginning to rely on simulation models of the electrical system to assist in the analysis (Frankena 1997a, Frankena and Morris 1997, 1998). These simulation models attempt to reflect the complex interplay of the numerous factors that affect the geographic scope of markets.

Transmission constraints play a particularly important role in defining geographic markets. Consider a hypothetical case in which there are two areas, North and South. Suppose that transmission capacity from North to South is fully utilized, the price of energy in the North is \$20/MWh, the charge for transmission service from North to South is \$1.50/MWh, and the price in the South is \$24/MWh. (See Figure 3.) In this case, North and South would be different geographic markets. For example, a 5% anticompetitive increase in the price of energy in the North (to \$21/MWh) would have no effect on energy transfers between North and South, on prices in the South, or on the output levels of generators in the South. As a result, generators located in the South would not be in the geographic market for purposes of evaluation of a merger in the North — even though transmission from the South

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<sup>1</sup> However, FERC's detailed methodology for defining geographic markets for use in merger analysis — known as Appendix A — is inconsistent in important respects with the sound economic principles of the *Merger Guidelines* and therefore is of uncertain reliability (Frankena 1998a). Moreover, in evaluating applications from individual utilities for market-based pricing, FERC uses a different, and also unreliable, methodology — known as a hub-and-spoke analysis — to define geographic markets.

**Figure 3. Example of Geographic Markets Separated by Transmission Constraints.**



to the North would be available. Also, a 5% increase in electric rates in the South would not affect sales from North to South since the existing transmission capacity is fully used.

### **Load Pockets**

In many cases, because of transmission constraints, during much of the year the total amount of energy that can be imported into a region is substantially less than the amount of energy consumed in the region. Such regions are known as *load pockets*. At least some of the generators located inside a load pocket must operate if local demand for energy is to be met. In that case, if a single company owned all generation in the load pocket, it would typically have market power.

Such a company could reduce the output of the generators inside the load pocket until imports filled the transmission capacity into the load pocket. At that point, the company could increase prices to a very high level, and users would have to pay

those prices unless they were prepared to do without energy. Unless there were some regulatory or political constraint on the ability of the company to reduce output or raise prices, the company could raise prices high enough to make such an anticompetitive strategy profitable. In such a case, the load pocket (or possibly a smaller area within the load pocket) would be a geographic market for analysis of the market power over energy of generators in the load pocket.

Load pockets are common. Examples of companies that own generating capacity that must operate in order to meet demands for energy in load pockets are Consolidated Edison of New York, Nevada Power, Pacific Gas & Electric (PG&E), SDG&E, Sierra Pacific Power, and Wisconsin Electric Power.<sup>2</sup>

## MARKET SHARES AND CONCENTRATION

In assessing generation market power, market shares are normally based on generating capacity in a relevant product and geographic market. There is no simple rule about the levels of market shares that are likely to confer market power on a single firm acting alone. In various regulatory and antitrust contexts, there is some point between about 30% and 50% at which the potential for a single firm to exercise market power typically receives increased scrutiny. However, a firm with a lower market share may have market power when its competitors are not able to increase their output significantly in response to a price increase. Conversely, a firm with a higher market share may not have market power if entry is easy.

In markets where two or more firms have substantial market shares, inferences about the likelihood that market power will be exercised simultaneously by such firms, either unilaterally or in collusion, are typically based on seller concentration in the market measured by the Herfindahl-Hirschman Index (HHI). The HHI is an *index of concentration* in a market. To determine the HHI for a market, one computes the market shares for the companies in the market and then calculates the sum of the squares of those market shares.

Table 2 illustrates how to calculate an HHI and provides an example in which a market with four sellers has a HHI of 3,000. The federal antitrust agencies and FERC call a market with an HHI greater than 1,800 "highly concentrated." An example of a market with an HHI of 1,800 is a market with five to six equal sized competitors.

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<sup>2</sup> Sources: Consolidated Edison, New York Department of Public Service 1996; Nevada Power and Sierra, Frankena 1997a; PG&E, 81 FERC ¶61,122 at 195; SDG&E, Southern California Edison and San Diego Gas & Electric 1996, Chap. 3.

<b>Table 2. Computing an Herfindahl-Hirschman Index (HHI).</b>		
	<b>Market Share</b>	<b>Share Squared</b>
Company A	40%	1,600
Company B	20%	400
Company C	30%	900
Company D	10%	100
HHI		3,000

Now let us consider the effect on the HHI in this illustrative market if there is a merger between two companies. If Company C acquired Company D, the HHI would increase to 3,600. Table 3 illustrates the calculation of the HHI.

<b>Table 3. Effect of a Merger on Example HHI.</b>				
	<b>Pre-merger Market Share</b>	<b>Pre-merger Share Squared</b>	<b>Post-merger Market Share</b>	<b>Post-merger Share Squared</b>
Company A	40%	1,600	40%	1,600
Company B	20%	400	20%	400
Company C	30%	900	40%	1,600
Company D	10%	100		
HHI		3,000		3,600

In markets with an HHI of at least 1,800, mergers that increase the HHI by more than 50 may raise competitive concerns under the DOJ/FTC *Merger Guidelines*. However, in practice the antitrust agencies do not often challenge mergers that would increase the HHI by less than 200 points or that would leave the HHI below 2,000 post-merger. An example of a merger that would increase the HHI by 200 points is one between two companies with market shares of 20% and 5%, respectively.

FERC uses different methodologies for defining geographic markets and computing market shares in merger cases and in market-based pricing applications. Also, while FERC makes inferences based on HHIs in merger cases, in market-based pricing applications FERC looks only at the market share of the firm requesting market-based pricing authority.

As a matter of policy, FERC approves market-based pricing for companies whose shares are under 20%; in practice, FERC also commonly approves market-based

pricing when shares are between 20% and close to 30%. Most utilities are able to pass FERC's structural standards for market-based pricing for electric energy given the way geographic markets are defined, the way shares are measured, and the market share standards used.<sup>3</sup> FERC may grant market-based pricing to an existing generating company in some cases in which the formation of that company as the result of a merger would raise substantial market power concerns.

While FERC's methodology for measuring market power in connection with market-based pricing applications is questionable, the notion that different structural thresholds are appropriate for merger and market-based pricing decisions is widely accepted. DOJ has suggested that in markets with HHIs below 2,500, it is likely to be in the public interest to deregulate prices in order to eliminate costs and distortions caused by regulation. (A market with four competitors, each having a 25% market share, has an HHI of 2,500.) Of course, a finding that the public would be better off without price regulation in a market with an HHI of 2,490 suggests that the public would be *even better off* if prices were deregulated *and* concentration were reduced below 2,490.

## ENTRY CONDITIONS

In antitrust parlance, even if a firm has a large market share or a market is highly concentrated, sellers will not have significant horizontal market power if it is *easy* for new sellers to enter the market. But, for entry to be easy in the antitrust sense, that entry must be not only feasible but also must be both timely and profitable as well.

Frequently, market power analyses incorrectly conclude that entry is easy because it *could* occur. However, the important question is not whether it could occur but whether it *would* occur in a timely manner in response to an attempt to exercise market power. For entry to be sufficiently easy to alleviate concerns about exercise of market power by incumbent sellers, new competitors must be able to enter a market quickly and make a profit doing so.

## Feasibility

Obviously, entry cannot constrain the exercise of market power if entry is not feasible. Thus, the first issue in an evaluation of entry conditions is whether entry would be prevented by regulations such as zoning rules, environmental permitting,

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<sup>3</sup> The Committee on Electric Utility Regulation (1998, p. 159) reports that, at the end of 1997, 62 investor-owned public utilities and 79 marketers affiliated with a public utility had received market-based pricing authority.

or requirements that an entrant demonstrate a "need" for additional capacity in a market with excess capacity.

### **Timeliness**

Under the standards used by the federal antitrust agencies and FERC, entry is not easy if more than two years would be required from initial planning to significant market impact. Most types of generating units and significant transmission facilities require longer than two years for planning, approval and construction.

### **Profitability**

If a new entrant cannot expect to cover its costs and earn a normal rate of profit by selling its output at competitive prices, then the threat of entry will not prevent an increase in prices above competitive levels. In areas of the United State that have excess generating capacity, entry that would prevent the exercise of significant market power may not be profitable for several years. Several years may be required for load growth to absorb existing excess capacity. Even where excess capacity does not exist at present, entry may not be profitable if the minimum efficient scale for a new generator would represent a substantial share of the market. In such a case, new entry could result in excess capacity that would depress prices below the level required to justify the entry.

Because of conditions relating to timeliness and profitability of entry, in most cases in which entry would take the form of new generating units, wholesale electric power markets do not presently satisfy traditional antitrust standards for easy entry. However, in some areas of the country there is no excess capacity, loads are growing quickly, and merchant gas-fired combined cycle generating plants are being set up with a gestation period of around three years. In such cases, the duration of concerns over generation market power for electric energy during peak periods might not exceed three years. Nevertheless, market power problems might last substantially longer during off-peak periods in areas where gas-fired combined cycle units would not be in the product market (because their variable costs of production would exceed competitive prices by more than 5%) and market power would hinge principally on ownership of nuclear and coal generators.

### **SIMULATION MODELS**

The traditional approach to assessing generation market power can be supplemented by analyses based on simulation models. Relevant models use regional data on generation capacity and costs, transmission capacity and costs, and demands for electric power. With these data, models can be used to determine the

geographic scope of markets and whether the existing (or a proposed) ownership pattern for generating plants is likely to lead to energy prices significantly above competitive levels. Simulation models capture market characteristics and interactions that are neglected by simpler traditional analytical methods.

The most difficult issue for analyses of generation market power based on traditional antitrust methods is to determine the geographic scope of competition. It is generally recognized that historic sales data do not provide a reliable basis for measuring the scope of geographic markets in electric energy for several reasons. First, public data on sales are annual aggregates while there are separate markets for energy during different times of the year. The fact that Utilities A and B both sold energy to Utility C during 1997 would not demonstrate that Utilities A and B were competing, since Utility A's sales may have occurred during winter off-peak hours while Utility B's sales occurred during summer peak hours.

A second problem is that sales data often do not allow one to determine ultimate origins or destinations of transactions. A large share of electric energy is sold by generating companies to power marketers or to other utilities that resell to other wholesale buyers. A third problem is that generators that have not supplied a market in the past may yet belong in a relevant market because they could provide supplies in response to a small price increase, and thus play a significant role in constraining prices.

Because one cannot rely on sales data to define the geographic scope of competition for electric energy, one must use data for the underlying determinants of competition — generating capacities and costs, transmission capacities and costs, and demands for energy in different areas. The most satisfactory way to employ such data is to build a model — a simplified representation — of the electrical system over a relatively wide region, such as the eastern half of the United States. Such a model can be used to estimate the geographic scope of competition during each time period, such as summer peak hours.

For example, suppose one is interested in determining the appropriate geographic market in which to evaluate the potential effects on market power of a merger between Illinois Power and Central Illinois Light. One could use a simulation model of the eastern United States to test whether the state of Illinois would be a relevant geographic market.

To illustrate the analysis, we return to the “thought experiment” described earlier in this chapter. The model would be used to determine whether a hypothetical company that owned all generating capacity in Illinois would find it profitable to raise energy prices significantly above competitive levels. If the answer to this question is no, one could determine whether a hypothetical company that owned all generation in, say, Illinois, Missouri, and Indiana would find it profitable to raise energy prices.

To answer this question, the model would bring to bear information about the factors that would constrain an exercise of market power by the hypothetical owner of generation. For example, the model would use information on generating capacity and costs in Kentucky, transmission capacity and costs from Kentucky to Illinois and other potential markets, and demands for energy in Kentucky and other potential markets. Combining all this information, the model would determine whether increased imports from Kentucky and elsewhere would impose a significant constraint on the ability of a hypothetical monopolist of generation in Illinois, Missouri, and Indiana profitably to raise prices.

A simulation model can assist not only in analyzing the geographic scope of competition but also in determining whether companies would be able to increase their profits by taking certain types of anticompetitive actions. In a state restructuring proceeding, for example, a simulation model could be used to determine whether any one of the larger utilities in the market would be able to increase its profits by withholding output or raising the prices that it bids into a power pool.

An analysis of the latter type is a valuable addition to a traditional market power analysis based on shares and HHIs. Suppose a traditional analysis shows that a company has a 35% market share. One still faces the question whether a 35% share is sufficient to give a company market power. The answer to this question depends on two issues that are not addressed by a market share analysis but that are taken into account by a simulation model:

- By how much would this company have to reduce its output to raise energy prices by, say, \$1/MWh? The amount of the output reduction depends on (i) the extent to which other generating companies would have the ability and incentive to expand output, and (ii) the extent to which customers would reduce consumption, in response to a \$1/MWh increase in energy prices. Other things equal, if competing generating companies would expand output substantially in response to a \$1/MWh increase in energy prices, then an attempt to exercise market power would be less profitable.
- How much profit contribution does the company that is raising prices give up on each MWh of sales that it must forego in order to bring about a price increase? The profit contribution is equal to the competitive market price of energy minus the incremental cost at the generating unit where output would be reduced. If the competitive market price were \$20/MWh and the incremental cost were \$19.90/MWh, the company would give up only \$0.10/MWh in profits on sales foregone. On the other hand, if the incremental cost were \$12/MWh, the company would give up \$8/MWh in profits on sales foregone. Other things equal, if the incremental cost is lower, the company would find an attempt to exercise market power less profitable.

The lesson from this example is that market power depends on matters that are not taken into account by simple market share calculations, and thus market share calculations can usefully be supplemented by analyses using a simulation model.

It is sometimes argued that, since simulation models take account of factors that are omitted from market share and HHI analyses, analyses using simulation models can entirely replace traditional analyses. This is not correct. Simulation models are particularly useful in analyzing *unilateral* exercise of *generation* market power over *electric energy*. However, simulation models appear to have limited ability to analyze issues relating to the likelihood of collusion and market power over capacity and ancillary services.

### OTHER TYPES OF MARKET POWER

Both methodologies that are used to evaluate generation market power — the traditional methodology based on market shares and HHIs and simulation models — may be adapted and supplemented to analyze other types of market power. Problems that may arise because of common ownership of generating capacity and transmission systems, or common ownership of generating capacity and natural gas transportation systems, can be analyzed in these ways.

Suppose that Utility A owns 5,000 MW of generating capacity in a market. Suppose further that Utility A can significantly affect the availability of transmission service required to deliver 2,000 MW of energy to the market from generators outside the market that are owned by other companies. Finally, suppose that Utility A can significantly affect the price of natural gas delivered to 1,000 MW of generating capacity in the market that is owned by other companies. Under these assumptions, one way of reflecting Utility A's competitive role in the market would be to base its market share on the 8,000 MW ( $= 5,000 \text{ MW} + 2,000 \text{ MW} + 1,000 \text{ MW}$ ) of capacity over which it has competitively significant control. One could also use a simulation model to investigate the implications of assuming that Utility A owned the full 8,000 MW of capacity.

One type of market power that plays an important role in restructuring proceedings relates to what is called *reliability must run generation*. Because of properties of electric transmission and distribution systems, under certain conditions a particular generating unit may have to operate to prevent thermal, voltage or stability problems that would threaten system reliability (Jurewitz and Walther 1997). In such cases, there may be a relevant market that contains a single generator that has a 100% market share and substantial market power.

## THE DIFFICULT TASK OF ASSESSING MARKET POWER STUDIES

Regulators, legislators and antitrust authorities face a difficult question: which market power studies proffered to them are based on reliable methodologies, assumptions and data? There is no simple answer, and thus no simple way for interested parties to avoid careful scrutiny of any study. The most reliable assessments of market power are likely to be based on a combination of traditional antitrust analysis following the DOJ/FTC *Merger Guidelines* and simulation modeling.<sup>4</sup>

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<sup>4</sup> For reasons indicated above, the methodology for evaluation of market power in the competitive analysis screens required by FERC's *Merger Policy Statement* is not reliable (Frankena 1998a). The same is true of FERC's hub-and-spoke methodology. Also, while simulation models can be useful, poorly designed models — such as those offered by applicants in the Primergy merger — obviously are not useful (see FERC's Primergy decision, 79 FERC ¶61,158 (1997)).

The preceding chapters of this report have discussed the nature of market power in the electric power industry and have described methods used to determine whether market power problems exist. In this chapter, we discuss approaches that may be used to eliminate, reduce and deal with market power problems.

In general, the preferred method for dealing with market power is to bring about changes in market structure that will eliminate the incentives for companies to behave in an anticompetitive fashion. Structural remedies, such as divestiture of generation or transmission facilities, will sometimes achieve this objective. Nonetheless, society cannot rely solely on structural remedies to deal with market power in the electric industry. Some industry activities have natural monopoly characteristics — examples include transmission, distribution and some ancillary services (or reliability must run generation). Where an activity is a natural monopoly, society may have no practical alternative to reliance on regulation of prices and other terms to mitigate market power.

Also, in some cases structural remedies for market power may sacrifice achievement of potential economies of scale and scope. For example, in small markets there may be a trade off between achieving economies of scale in production and having enough sellers for markets to be competitive. Also, it is frequently argued that potential economies of scope would be lost if some forms of vertical integration were prohibited.

## **STRUCTURAL VERSUS BEHAVIORAL APPROACHES**

Approaches to dealing with market power fall into two categories: structural and behavioral. Structural measures change characteristics of a market so that firms no longer have market power. That is, firms no longer find it profitable to reduce their output and take other steps that raise prices. Rather than removing market power, behavioral measures attempt to prevent companies with market power from acting anticompetitively.

### **Structural Remedies**

When generation market power is found to be significant, the obvious structural remedy is for firms with large market shares to sell generating units so that market shares and concentration are reduced. PG&E and SoCal Edison have recently been induced by state regulators to sell generating plants in a manner that will reduce

market shares and concentration. As we discuss later, provisions for incumbent generators to sell generating capacity should typically be included in comprehensive restructuring plans when significant generation market power is found to exist.

Sale of generating units is not the only potential structural measure to alleviate generation market power, however. If generation market power is likely to be temporary, it may be sufficient for companies to enter into long-term contracts to sell capacity or energy for the pertinent period. Another structural approach to dealing with generation market power is to change regional transmission pricing in ways that would broaden geographic markets and lower concentration.<sup>5</sup> Along these lines, in its 1998 order approving the merger of Louisville Gas & Electric and Kentucky Utilities, FERC relied in part on commitments by the merging companies to sell energy for a period of years and to join the proposed Midwest independent system operator (ISO), which plans to provide transmission service under a regional tariff (82 FERC ¶61,308). Other utilities are now offering similar commitments as a *quid pro quo* for merger approval. In their successful merger application at FERC in 1997, Wisconsin Electric Power and Edison Sault Electric committed to make available to others a certain amount of transmission service to the Michigan Upper Peninsula. This commitment reduced their share in an Upper Peninsula market.

In principle, another structural remedy available to reduce generation market power is expansion of transmission capacity. FERC imposed requirements for expansion of transmission capacity to deal with market power issues raised by the FirstEnergy and Alliant mergers. In many cases, however, transmission system investments would take too long to provide a remedy, would be too costly, or would not in fact add significantly to the transfer capability of the grid.

To deal with transmission market power, one structural measure is to separate ownership of generation and transmission facilities. Such separation is clearly the most direct and effective method to prevent utilities from using control over transmission to foreclose competition faced by their generators. A number of foreign countries, including Argentina and Peru, have separated ownership of generation and transmission, and some northeastern states are doing so, at least insofar as non-nuclear generation is concerned.

**Independent System Operators.** An alternative to separation of ownership of generation and transmission is for a utility that owns generation to turn over to a regional independent system operator (ISO) control over pricing, scheduling, curtailment, operation and maintenance, and expansion of its transmission system.

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<sup>5</sup> Of course, transmission should be priced in a manner that provides the correct signals for use of transmission capacity and for location of new generating plants. Transmission pricing should not be distorted in an attempt artificially to broaden markets. Also, reductions in transmission prices may not broaden markets if increased use of transmission results in congestion on the grid.

ISOs have been set up in several United States regions with the encouragement of the states and FERC.

However, there are some difficulties with ISOs as remedies for transmission market power. First, there are concerns about whether ISO governance structures sufficiently curb the influence of incumbent utilities that continue to own generation and power marketing operations. An ISO may not eliminate the role of incumbent utilities in matters such as transmission expansion decisions.

Second, there are concerns about whether ISOs have sufficient responsibilities and powers. The powers of existing and proposed ISOs vary. For example, the Texas and Midwest ISOs do not serve as control area operators with responsibility for dispatch of generating units.

Third, there is a significant debate about how to provide the correct incentives so that an ISO will manage the transmission system so that its operation, pricing and expansion are efficient. Will ISO committees with representatives of many stakeholders make decisions that allocate resources efficiently? Will the managers and staffs of an ISO be rewarded if

*"One potential difficulty with the nonprofit status of ISOs is the lack of profit incentives to operate efficiently and to make economically appropriate investment decisions regarding expansion of the transmission grid to address transmission bottlenecks. ISO governing bodies may be able to design the employment contracts of ISO managers to provide such incentives." (FTC 1998b).*

they make day-to-day decisions that promote efficient resource allocation, and penalized if they do not? One issue is whether non-profit ISOs can be expected to perform as well as for-profit ISOs. (See insert.)

Finally, there are concerns about the process of establishing regional ISOs. With a few exceptions — for example, California, New York, and Texas — individual states do not have the authority to require ISOs that would qualify as *regional*. While FERC has required that certain merging companies join ISOs, it has not attempted to require establishment of ISOs outside areas of the country that have tight power pools (New England, Pennsylvania-New Jersey-Maryland).

Distribution and fuel supply market power may also be dealt with by divestitures. To deal with distribution market power, utilities and their affiliates could be prohibited from engaging in retail marketing of electricity to customers in the geographic areas in which they own distribution facilities. While this approach has not been used in the electric industry to deal with distribution market power, it has a parallel in the telecommunications industry: the local Bell phone monopolies are not permitted to provide long distance service within their regions, and will not be permitted to do so until they demonstrate that they have sufficiently opened their local networks to competitors.

To deal with fuel supply market power concerns, SDG&E has been required to divest gas-fired generating plants and PacifiCorp was required to divest two of Peabody's coal mines (see Chapter 8 below).

Companies could also be prohibited from owning both regulated monopoly facilities and competitive facilities in order to eliminate the problems of discrimination, improper information sharing, cross-subsidization and self-dealing that sometimes arise when there is common ownership.

## Behavioral Remedies

Behavioral remedies allow market power — or anticompetitive incentives — to continue but attempt to prevent companies from behaving in anticompetitive ways that increase their profits. Behavioral remedies are inherently regulatory. Typically, there must be administrative mechanisms for monitoring behavior, adjudicating complaints, imposing sanctions, and overriding company decisions on prices, outputs, services and investments.

Behavioral remedies typically involve regulation or conduct rules. Here are five examples of behavioral remedies:

*Dominant firm regulation* is sometimes used to limit the prices that can be charged by firms with market power. Typically, the dominant firm in a market will face price regulation even while other suppliers operating in the market are not regulated. This approach was used by the Federal Communications Commission to regulate AT&T's long distance prices until 1996, even as other long distance firms were taking market share. The FCC removed price regulation when it determined that AT&T no longer had market power.

*Monitoring and mitigation plans* are being put in place to deal with generation and transmission market power in California and other regions with electric power auction markets. Under these plans, ISOs will engage in market surveillance in an attempt to detect and deter anticompetitive behavior. Frankena (1998b) discusses the likely ineffectiveness of these ISO surveillance schemes in detecting and deterring exercises of market power, while Raskin (1998) addresses the high costs these schemes are likely to impose on electric power markets.

*Restrictions on a Utility's Use of Transmission Capacity* may be used in an effort to prevent foreclosure of other users. Merging companies have agreed to various limits on, and lower priorities for, their own use of their transmission systems.

*FERC's Order 888 and 889* transmission open access rules, which are intended to address transmission market power. These rules mandate that public utilities unbundle generation and transmission and provide to others the same types of

transmission services they use themselves — with comparable prices, terms, conditions and information for all.

*Codes of conduct* governing affiliate relations for companies that own both regulated monopoly and competitive facilities. These codes and related rules may restrict permissible organizational forms in order to separate monopoly and competitive activities; prohibit self-dealing; prescribe transfer pricing and other accounting methodologies to limit cross-subsidies; prohibit sharing of certain types of information; and mandate disclosure, reporting and equal access to information to facilitate oversight and prevent discrimination (Norton and Grabow 1998).

The choice between structural and behavioral remedies is not a pure one. The issue is largely the extent to which reliance is placed on behavioral remedies. Even if primary reliance is placed on structural remedies, there may be little alternative to reliance on behavioral remedies to deal with residual market power, including some problems that arise from monopolies over transmission and distribution.

## DIFFERENCES BETWEEN ANTITRUST AGENCIES AND REGULATORS

The Department of Justice (DOJ) and the Federal Trade Commission (FTC) have traditions of preferring structural to behavioral remedies for market power — particularly for horizontal market power. In dealing with mergers in a wide variety of industries, the federal antitrust agencies commonly require divestitures to settle complaints. The agencies sometimes accept structural remedies that are intended to bring about new entry or lower entry barriers.

In the case of the electric power industry, the antitrust agencies have recommended primary reliance on structural remedies to deal with market power. Both agencies recommended that FERC require ISOs rather than rely on Order 888 to deal with transmission access problems (DOJ 1995, FTC 1995). Recently, the director of the FTC's Bureau of Competition noted that "Although FERC Order No. 888 mandates open access, there remains a concern that incentives and opportunities for discrimination may still be present, through either unilateral or collective action, and rival power generators could be disadvantaged" (Baer 1997).

In comments on the New England Power Pool's application for market-based pricing, the FTC staff as well as the Maine attorney general recommended against substantial reliance on market surveillance plans because of difficulties in detecting anticompetitive behavior and preventing it through behavioral rules (FTC 1998a, Frankena 1998b). Also, the United States assistant attorney general for antitrust cautioned FERC against following "an overly regulatory approach to merger review." (See sidebar.)

*"While I recognize, of course, that the Commission is a regulatory agency, and that the electric power industry has long been highly regulated, restructuring obviously is intended to move away from that paradigm. We at the Department hope and expect that market forces will become the primary determinants of wholesale electric power rates. And, in that context, mergers that substantially lessen competition should be allowed to proceed only if a court-imposed consent decree, or set of Commission-imposed merger conditions, offers a permanent, preferably structural remedy for the anticompetitive effects of the merger. More specifically, I would urge the Commission to reject rate freezes or rate roll-backs as conditions for approval of mergers creating structural competitive problems in generation. Such remedies typically are short-term, and do not in any way address the real competitive effects of the merger. Even in the short term, there will often be reason to doubt that the frozen rates would be as low as competitive rates. Finally, based on a century of experience, I would further emphasize that the Department is also highly skeptical of any relief that requires judges or regulators to take on the role of constantly policing the industry. Relief generally should eliminate the incentive or the opportunity to act anticompetitively rather than attempt to control conduct directly. We are institutionally skeptical about code-of-conduct remedies. The costs of enforcement are high and, in our experience, the regulatory agency often ends up playing catch-up, while the market forces move forward and the underlying competitive problems escape real detection and remediation." (Klein 1998, pp. 17-18).*

FERC approved the Enova/Pacific Enterprises electric-gas merger subject to prohibitions on inappropriate sharing of information and discrimination, and provisions for separation and transparency of certain transactions. By contrast, DOJ required divestiture of SDG&E's gas-fired generating plants. The director of the FTC's Bureau of Competition observed that FERC's "approach to remedies in this case illustrates the general inclination of regulatory agencies to use conduct remedies rather than structural relief" (Baer 1997, n. 25). However, it should be added that state commissions — notably California's — have imposed structural remedies.

## ADVANTAGES OF STRUCTURAL REMEDIES

Several reasons for preferring structural to behavioral remedies have been explained by the director of the FTC's Bureau of Competition:

*"A behavioral approach...has several drawbacks. First, it does not eliminate the incentive and opportunity to engage in exclusionary behavior. Rules can try to limit the opportunity, but few rules are invulnerable to evasion. Second, detection of violations can be very difficult. For example, discrimination in access could take the form of a subtle reduction in quality of service, whose effects could be difficult to identify and measure. Third, behavioral rules can require long-term monitoring of compliance, which can be a costly process.... Fourth, it*

*may be difficult to know whether we have selected the right rules. Even a simple cease-and-desist order, which is commonly used in antitrust cases, can be difficult to frame, because we do not want to prohibit too little or too much. More complex orders, especially those that try to guide conduct through affirmative requirements, can be more difficult to frame properly" (Baer 1997).*

The principal economic rationale for relying on behavioral rather than structural remedies is that structural remedies may prevent achievement of economies of scale and scope. The antitrust agencies sometimes rely on behavioral remedies in an attempt to limit potential anticompetitive effects of vertical mergers without sacrificing economies of scope (Baer 1997, n. 12).

### INEFFICIENT REGULATION

One obstacle faced by efforts to replace regulation with competition in potentially competitive markets is that society does not always acknowledge the costs and limitations of regulation. While this point applies to many types of regulation, the discussion here will focus on regulation of prices. Price regulation imposes substantial costs.

First, regulated prices are below the efficient level in many circumstances. This is particularly true in the case of electric power, since the value of a MWh of energy may vary by hundreds of percentage points over the course of a day. Regulators lack the resources to determine efficient price levels, and they lack the resources to change regulated prices as cost and demand conditions change. Furthermore, regulators may base regulated prices on incorrect economic analysis. For example, regulators often set prices based on the average historical cost of tangible assets. Prices set on this basis may have little relationship to the determinants of competitive or efficient prices.

Second, price regulation limits the ability of regulated firms to respond to changes in technology, cost and demand conditions, and deters new investments, quality improvements, introduction of new services, and entry by reducing returns on pro-competitive activities. This distortion is likely to be greatest in industries — including the formerly staid electric power industry — that are undergoing important changes and in which future risks will be substantial.

Third, it is also important to remember that government regulations involve substantial administrative costs both for the industries being regulated and for the government.

Fourth, special interests are often over-represented in the regulatory process, compared to the consumer interest, making predictable arguments to protect their

parochial interest in continuing regulation. Consequently, prices and services in regulated industries depart, often considerably, from those that would have prevailed in the markets that regulators displaced (Peltzman 1989).

In addition to its costs, a serious deficiency of price regulation is that regulated prices may well be substantially above competitive prices in some circumstances, even if they are below competitive prices in others. In such cases, utilities selling at regulated prices may actually be exercising significant market power. Such regulatory price gaps may be significant in the case of off-peak services, in regions with excess capacity, and for utilities with high average historical costs.

The limits of regulation, including price regulation, imply that consumers will typically be better off with structural rather than regulatory measures to address market power when structural remedies are an option. It should be recognized, however, that the discomfort of some regulators with reliance on markets to determine prices does not stem solely from concerns about market power. Some regulators are concerned that, without price regulation, consumers may become the victims of price gouging by unscrupulous sellers. We suggest that price regulation is not the best response to potential deceptive and unfair trade practices. Rather than throwing out the benefits of the market, consumer protection concerns are more properly addressed by measures to improve the information received by consumers so that markets can perform efficiently.

## RELIANCE ON ANTITRUST ENFORCEMENT

It is not uncommon to hear the argument that market power problems can be dealt with adequately by enforcement of the antitrust laws. This argument is not correct. First, while the Sherman Act makes

*"...a company with market power does not violate the antitrust laws merely by charging monopoly prices..."*

anticompetitive agreements and exclusionary conduct unlawful, a company with market power does not violate the antitrust laws merely by charging monopoly prices or limiting its output. Also, competitors in a concentrated market may be able to coordinate their pricing, output and other decisions in anticompetitive ways that are not susceptible to challenge under the antitrust laws.

Second, illegal behavior is not easily detected, and this would certainly be the case in complex electricity markets. Even when illegal behavior is detected, it is expensive, time consuming, and sometimes perhaps impossible to carry the burden of proving illegality to a court. In the meantime, much injury may have been done to consumers by firms exercising market power. One should also recognize that

antitrust enforcement does not deter all illegal anticompetitive behavior, even of a criminal nature, as revelations of dramatic price fixing conspiracies demonstrate.

Third, while the antitrust laws permit legal challenges to certain types of anticompetitive conduct, antitrust authorities generally cannot change existing market structures that are not conducive to competition. Issues of market structure in the electric industry must, therefore, be addressed primarily in restructuring legislation or proceedings. (See insert.)

From the United States assistant attorney general for antitrust:

*"[T]o whatever extent restructured electric power markets are too highly concentrated to yield pricing at or near competitive levels, the antitrust laws provide no remedy."* (Klein 1998, p. 5).

Fourth, certain anticompetitive conduct may be immunized from antitrust challenge by the state action doctrine, which shields anticompetitive behavior that is specifically authorized and actively supervised by a state. For example, the director of the FTC's Bureau of Competition has raised the possibility that the state action doctrine may shield the operations of ISOs (Baer 1997).

Notwithstanding the limits on antitrust enforcement, as greater reliance is placed on markets rather than regulation to determine prices and allocate resources, the importance of protecting competition in electric power markets through enforcement of the antitrust laws will increase. Both federal antitrust agencies are therefore devoting increasing attention to this industry. Aside from mergers, in 1996 DOJ sought to enjoin an Oklahoma city from refusing to extend or connect water and sewer lines to consumers unless they also bought their electric power from the city. DOJ alleged that this conduct constituted *per se* unlawful tying and that it reduced competition between the city and an electric cooperative.

In 1997, DOJ challenged an agreement between Rochester Gas & Electric and a university. DOJ charged that RG&E used financial threats and rewards to induce the university to abandon its plan to build a generating plant that would have competed with RG&E (Klein 1998, pp. 5-6). After a judge ruled that the agreement between RG&E and the university was not protected by the state action doctrine, DOJ's complaint was settled by invalidation of the agreement and a prohibition on RG&E from entering into similar agreements with competitors.

## OPPORTUNITIES FOR STRUCTURAL REMEDIES

As a practical matter, the ability of policy makers today to bring about divestitures is limited to situations in which companies agree to "voluntary" divestitures to obtain approval for something they very much want — such as recovery of stranded costs, approval of mergers, or approval of market-based pricing. The ongoing

divestitures of generation in California and the northeast states are occurring principally because divestiture is the *quid pro quo* for stranded cost recovery.

A lesson that should not be missed is that the states may have only one chance to bring about divestitures in the electric power industry — namely, as a price for whatever stranded cost recovery will be allowed. If a deal for stranded cost recovery has been struck without adequate divestiture provisions, the opportunity will be gone. It should be noted that some state legislatures have even discarded the divestiture option before evaluating market power.<sup>6</sup>

In Chapter 10 we will discuss whether policy makers have adequate authority to deal with market power and how federal legislation might provide additional authority for states or FERC to address market power directly with structural remedies, instead of indirectly as a result of merger reviews or market-based pricing decisions.

## CONCLUSIONS

For numerous reasons, policy makers should look first to structural remedies to shape the electric power industry into a competitive marketplace in generation and retail services. Notwithstanding a preference for structural remedies, a number of rationales can be offered for using behavioral remedies as well — mainly to deal with natural monopolies and other situations where structural remedies would cause unacceptable losses in economies of scale and scope. The next two chapters of this report will discuss remedies for market power in the context of mergers and retail restructuring proceedings.

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<sup>6</sup> The Pennsylvania Electricity Competition Act specifically precludes divestiture of generation assets as a requirement for restructuring (66 Pa. C. S. §2804(5)).

The techniques described earlier for assessing market power are used in a variety of settings — for example, to evaluate proposals for deregulation, divestiture requirements, and mergers. This chapter reviews recent experience with electric utility mergers, discusses how such mergers may increase market power, and finally considers how regulators and antitrust authorities have approached the market power issues raised by these mergers.

### **RECENT ELECTRIC UTILITY MERGERS**

Electric utility mergers are not a new phenomenon, but the number of completed mergers between large electric utilities has increased in recent years. For investor-owned utilities large enough to appear on a standard wall map, one or two mergers were completed in almost every year from 1986 through 1996, with the result that the number of independent utilities on the map declined by 15 (12%). The number of utilities on the map then declined by another 4 during 1997 and will decline by 5 to 10 more by mid-1999, depending on the outcomes of the pending Western Resources/Kansas City Power & Light, Allegheny Power System/DQE, American Electric Power/Central & South West, Sierra Pacific/Nevada Power and Consolidated Edison/Orange & Rockland mergers. Even if all pending mergers are completed, the number of larger independent utilities visible on the map will stand at 92. Thus, we may expect further mergers to be proposed.

But the number of completed mergers is only part of the story. While a majority of announced electric utility mergers have eventually been completed, in the past ten years 14 mergers have been abandoned in the face of opposition and delays by target companies, stockholders, bankruptcy courts, and state and federal regulators. Table 4 lists the mergers and takeovers between investor-owned electric utilities that were proposed from 1994 through May 1998.

A major development on the merger front since 1995 has been the announcement of a dozen “convergence” mergers involving electric utilities and companies engaged in the transportation or retail distribution of natural gas. These are listed in Table 5.

<b>Table 4. Investor-Owned Electric Utility Mergers, 1994 to Present</b>		
<b>Utilities (Survivor in Bold)</b>	<b>Year (Announcement to Outcome)</b>	<b>Outcome</b>
<b>MidAmerican Energy</b> Midwest Resources Iowa-Illinois Gas & Electric	1994-95	Merged
<b>New England Electric System</b> Nantucket Electric	1994-96	Merged
<b>Altus</b> Washington Water Power Sierra Pacific Resources	1994-96	Terminated by WWP
<b>Primergy</b> Northern States Power Wisconsin Energy (Wisconsin Electric Power)	1995-97	Rejected by FERC
<b>PECO Energy</b> PPL Resources (Pennsylvania Power & Light)	1995	Rejected by PPL
<b>Ameren Corp.</b> Union Electric CIPSCO (Central Illinois Public Service)	1995-97	Merged
<b>New Century Energies</b> Public Service Co. of Colorado Southwestern Public Service	1995-97	Merged
<b>Constellation Energy</b> Baltimore Gas & Electric Potomac Electric Power	1995-97	Abandoned
<b>Alliant</b> WPL Holdings (Wisconsin Power & Light) IES Industries Interstate Power	1995-98	Merged
<b>MidAmerican Energy</b> IES Industries	1996	Rejected by IES shareholders
<b>Maxim Energies</b> UtiliCorp United Kansas City Power & Light	1996	Rejected by KCPL shareholders
<b>Western Resources</b> Kansas City Power & Light	1996-98	Pending
<b>Conectiv</b> Delmarva Power & Light Atlantic Energy	1996-97	Merged
<b>FirstEnergy</b> Ohio Edison Centerior Energy	1996-97	Merged
<b>Allegheny Energy</b> Allegheny Power System DQE (Duquesne Light)	1997-	Pending
<b>Wisconsin Energy (Wisconsin Electric Power)</b> ESELCO (Edison Sault Electric)	1997-98	Merged
<b>LG&amp;E Energy (Louisville Gas &amp; Electric)</b> KU Energy (Kentucky Utilities)	1997-98	Merged
<b>WPS Resources (Wisconsin Public Service)</b> Upper Peninsula Energy	1997-98	Approved by FERC
<b>American Electric Power</b> Central & South West	1997-	Pending
<b>Sierra Pacific Resources</b> Nevada Power	1998-	Announced
<b>Consolidated Edison (of New York)</b> Orange & Rockland Utilities	1998-	Announced

**Table 5. Convergence Mergers.**

<b>Electric Utility</b>	<b>Gas Company</b>	<b>Years (Announcement to Outcome)</b>	<b>Outcome</b>
Puget Sound Power & Light	Washington Energy	1995-97	Merged
Texas Utilities	Enserch	1996-97	Merged
Portland General Electric	Enron	1996-97	Merged
Houston Industries (Houston Lighting & Power)	NorAm Energy	1996-97	Merged
Enova (San Diego Gas & Electric)	Pacific Enterprises (Southern California Gas)	1996-98	Approved
TECO Energy (Tampa Electric)	Lykes Energy (Peoples Gas System)	1996-97	Merged
Duke Power	PanEnergy	1996-97	Merged
Long Island Lighting	Brooklyn Union Gas	1996-	Pending
PG&E (Pacific Gas & Electric)	TECO Pipeline	1996-97	Merged
PacifiCorp	TPC (Tejas Power)	1997	Merged
PG&E	Valero Energy	1997	Merged
NIPSCO (Northern Indiana Public Service)	Bay State Gas	1997-	Pending

## HOW MERGERS AFFECT MARKET POWER

Mergers involving electric power companies may increase generation, transmission and fuel supply market power, as well as increase or create opportunities for various affiliate abuses. Mergers between electric and gas companies may raise fuel supply market power issues and retail market power issues. For these reasons, mergers deserve close scrutiny by regulators and antitrust authorities.

### Mergers between Electric Utilities

Mergers between electric utilities may increase generation and transmission market power, and in reviewing these mergers antitrust authorities consider effects on both. By contrast, in evaluating the competitive effects of these mergers, FERC now focuses exclusively on generation market power. FERC generally ignores effects of mergers on transmission market power because the agency assumes that such market power is eliminated by its Order 888, which requires open access

nondiscriminatory transmission service, and Order 889, which requires electronic posting of available transmission capacity and standards of conduct.<sup>7</sup>

However, it is obviously one thing to tell companies to behave in a certain way and quite another actually to get them to forgo opportunities to increase their profits. Surfacing complaints relating to how transmission capacity is defined, measured, reported, reserved for native load uses, scheduled and curtailed (*Foster Electric Report*, April 29, 1998, p. 1) suggest that FERC's reliance on the regulatory prescriptions in Order 888 is not warranted.

While ignoring effects of mergers on transmission market power, FERC shows concern for such market power in other contexts. For example, FERC found that Washington Water Power apparently violated numerous rules in providing transmission service to its affiliated power marketer (*Foster Electric Report*, May 13, 1998, pp. 4-6). Also, FERC recognizes that new industry reliability rules and practices could be used to reduce access to transmission, and FERC commissioners and staff are promoting use of ISOs to reduce transmission market power as well as for other reasons.

To appreciate the potential effect of a merger on transmission market power, suppose that GenCo owns a large share of generating capacity in the Peninsula region. Suppose that TransCo has the ability to influence the terms on which competing generators outside Peninsula are able to transmit energy to buyers in Peninsula. As long as TransCo owns no generation in Peninsula, TransCo has an incentive to sell transmission service to generators desiring to sell energy in Peninsula. Now suppose that GenCo and TransCo merge. The merged company may now have both the ability and the incentive to restrict the availability of transmission service to reach Peninsula in order to raise the prices at which it can sell energy from the GenCo generators.

The proposed merger of Northern States Power and Wisconsin Electric Power to form Primergy raised important concerns about both generation and transmission market power. FERC chose to dismiss concerns about transmission market power in light of the assumed efficacy of Orders 888 and 889, but decided that the merger raised serious generation market power problems. Two days after FERC's decision, Primergy was abandoned.

We do not mean to suggest that generation market power should take a back seat to transmission market power concerns at FERC when mergers are examined. As stated earlier, realizing the benefits of a restructured electric market depends

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<sup>7</sup> FERC does, however, consider whether a merger would enable the merged firm to reduce the availability of transmission service across congested interfaces for competing suppliers. See Committee on Electric Utility Regulation (1998), pp. 172-73.

*"Non-horizontal mergers may be used by monopoly public utilities subject to rate regulation as a tool for circumventing that regulation. The clearest example is the acquisition by a regulated utility of a supplier of its fixed or variable inputs. After the merger, the utility would be selling to itself and might be able arbitrarily to inflate the prices of internal transactions. Regulators may have great difficulty in policing these practices, particularly if there is no independent market for the product (or service) purchased from the affiliate. As a result, inflated prices could be passed along to consumers as "legitimate" costs. In extreme cases, the regulated firm may effectively preempt the adjacent market, perhaps for the purpose of suppressing observable market transactions, and may distort resource allocation in that adjacent market as well as in the regulated market. In such cases, however, the Department recognizes that genuine economies of vertical integration may be involved. The Department will consider challenging mergers that create substantial opportunities for such abuses." (DOJ 1984, Section 4.23, footnote omitted).*

critically on the elimination or mitigation of significant market power both in generation and transmission. It is simply the case that FERC should examine both vertical and horizontal market power when considering mergers between electric utilities.

### Convergence Mergers

If a single company owns both generators and natural gas pipelines that supply gas to competing generators, it may have the ability and incentive to raise the price of gas delivered to competing generators. DOJ, FERC and the California commission concluded that the proposed merger of Enova (owner of SDG&E's generating plants) and Pacific Enterprises (owner of Southern California Gas's transportation facilities) would result in fuel supply market power. To resolve such problems, DOJ and the California commission required that the merged firm divest SDG&E's gas-fired generators. The California commission also required the merged firm to divest options to purchase two gas pipelines. Both the California commission and FERC also imposed a number of behavioral restrictions.

A fuel supply market power issue arose in 1997 in connection with the proposed merger between PacifiCorp and the corporate parent of Peabody Coal, which supplies coal to large generating plants in the southwestern United States. The FTC reasoned that as a result of the merger PacifiCorp was likely to have the ability and incentive to raise prices of coal from two Peabody mines to competing generators because this action would raise market prices for electric energy during

off-peak hours. The FTC therefore required that PacifiCorp divest the two Peabody mines to avoid an antitrust complaint.<sup>8</sup>

Convergence mergers may raise additional competitive concerns related to information sharing, cross-subsidization and self-dealing (see Insert). The FTC reasoned that PacifiCorp might gain access, through Peabody's coal contracts and coal supply relationships, to highly sensitive data about competitors' costs and to information about the operating conditions of competing generators. The FTC was concerned that such information would enable PacifiCorp to identify situations in which it could raise prices because it did not face competition.

In addition, a horizontal market power issue is raised by mergers between electric and gas distribution utilities that have overlapping retail territories, and also when an electric distribution company proposes to merge with a gas pipeline that can influence the retail price of gas sold to customers of the electric company. In such cases, a merger may increase horizontal market power by reducing competition between electricity and gas.

Some customers can choose between gas and electricity for some of their energy requirements, and a merger between gas and electric utilities with overlapping retail territories is therefore likely to eliminate some price and non-price competition. For example, such a merger might eliminate competition to reduce costs and prices, to provide superior customer service, to provide incentives for developers of all-electric housing, and to provide discounts for customers with gas air conditioners and electric heat pumps. Some studies have concluded that costs are actually lower when electric and gas utilities are separately owned than when there is a combination utility (Frankena and Owen 1994, pp. 130-33). Nonetheless, FERC typically leaves consideration of the effects of mergers on retail competition to state regulators, and the federal antitrust agencies have not challenged electric-gas mergers based on concerns over retail electric-gas competition.

There are a number of possible explanations for why the antitrust agencies may have concluded that they would not prevail in court in a merger challenge based on reduced retail competition between electricity and gas. Merger applicants may have argued:

- At present and forecast prices for electricity and gas in some parts of the country, electricity is not competitive with gas for uses such as space heating.
- The reduction in competition will not be significant if there is open access to the electric or gas distribution system.

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<sup>8</sup> Ultimately, PacifiCorp was outbid by Texas Utilities, which had arranged to sell Peabody Coal.

- Requirements for uniform service territory tariffs will prevent a merger involving a partial overlap of customers from having a significant effect.

Also, if state regulators believe they can protect retail ratepayers from the exercise of market power by combination utilities, political considerations may weigh against a federal challenge. Because convergence mergers are likely to continue to be proposed, this heightens the importance of scrutiny of such mergers by state regulators.

## EVOLUTION OF FERC'S MERGER POLICY

FERC's concern over the competitive effects of mergers was initially heightened by three large mergers proposed in the late 1980s — PacifiCorp's acquisition of Utah Power & Light, SoCal Edison's attempt to acquire SDG&E, and Northeast Utilities' acquisition of Public Service Company of New Hampshire. Each of these mergers was the subject of FERC and state proceedings that lasted for over two years. The California commission rejected the SoCal Edison/SDG&E merger because of its effects on competition as well as other concerns, while FERC imposed conditions on the PacifiCorp and Northeast Utilities mergers to mitigate transmission market power.

By contrast, during the early 1990s FERC approved all merger proposals — including transactions as large as Entergy's acquisition of Gulf States Utilities — without serious analysis of competitive effects. FERC did not analyze competitive effects when the merging companies agreed to provide open access transmission service, as all did. FERC's reasoning was that the pro-competitive effects of open access under a single-system tariff were sufficient both to prevent an increase in transmission market power and to offset any increase in generation market power.

By 1994, some FERC commissioners were speaking out on the weaknesses of FERC's merger policy in an era in which increasing reliance was being placed on competition. Also, after Order 888 imposed open access on all public utilities in 1996, it was no longer possible for merging companies to avoid scrutiny of competitive effects by offering open access. In 1996, FERC formally changed its approach to merger evaluation by issuing its *Merger Policy Statement*. In 1997, FERC's adverse finding regarding the competitive effects of the proposed Primergy merger was quickly followed by abandonment of the transaction. FERC also found that the Enova/Pacific Enterprises merger raised significant fuel supply market power problems.

More recently, FERC has decided that some merging utilities must provide greater transmission access in order to overcome concerns about market power over municipal and cooperative utilities located in the merging companies' territories. FERC has also required that some merging companies turn control of their

transmission systems over to a regional ISO, typically after the merging companies have offered to do so. By the first half of 1998, as a *quid pro quo* for avoiding hearings on market power, it was becoming routine for applicants to offer commitments to join an ISO and to sell a few hundred megawatts of energy for a few years to offset potential generation market power problems.

FERC has stated that it will leave to states the task of evaluating the effects of mergers on retail competition while FERC focuses on effects on wholesale competition. However, when states open some or all retail sales to competition, utilities have more electric power that they are free to sell — either at wholesale or retail — at market prices. As a result, the introduction of retail competition will change market shares, concentration and market power at the wholesale level. It follows that the effect of a merger on future wholesale competition cannot be evaluated without taking into consideration future changes in retail customer choice. In any case, FERC requires two analyses of the effects of mergers on wholesale competition in electric energy, one based on “available economic capacity,” which assumes existing levels of retail competition, and a second based on “economic capacity,” which assumes that all native load customers have the ability to choose among energy suppliers.

## STATE REGULATORY COMMISSIONS

Regulatory commissions of states in which retail customers are served by a merging utility typically must approve a proposed merger. There are exceptions, for example, when the structure of a merger transaction does not change control over the jurisdictional assets in a state. For a number of mergers, state commissions have considered the same competitive issues that FERC has evaluated, as well as additional issues such as retail competition. This was true of the California commission in the SoCal Edison/SDG&E merger, the Wisconsin commission in the Primergy merger, and the Pennsylvania commission in the Allegheny/DQE merger. The California commission’s rejection of the first of these mergers caused that merger to be abandoned. Commission staff in Wisconsin opposed the Primergy merger, which was rejected by FERC before the Wisconsin commission reached a decision. The Pennsylvania commission approved the Allegheny/DQE merger only on condition that the utilities join a functioning ISO, while that merger is still pending at FERC.

## ANTITRUST AGENCIES

In addition to requiring approval by FERC and state commissions, utility mergers can be challenged in court by the federal antitrust authorities, state attorneys general, and private parties for violation of the Clayton Act, which prohibits mergers that may substantially lessen competition.

During FERC's evaluation of the proposed SoCal Edison/SDG&E merger, DOJ participated as an intervenor in the FERC proceedings. Since then, rather than participate in regulatory proceedings, the federal antitrust agencies have carried out independent investigations of utility mergers that raised potential concerns. However, with the exceptions of the Enova/Pacific Enterprises and PacifiCorp/Peabody vertical mergers, the antitrust agencies have not issued complaints or obtained remedies.

Antitrust action may in certain cases be deterred by concerns that the agencies will not succeed in carrying their burden of proof to persuade a federal district court to block a merger, particularly if a merger has been approved by FERC. The United States assistant attorney general for antitrust has suggested that even if DOJ concludes internally that a utility merger is likely to be anticompetitive, DOJ may be unable to convince a court to agree given the limited real world market transactions data available to demonstrate key points such as the geographic scope of competition. This concern led the US assistant attorney general to suggest either a moratorium for a few years on mergers between large directly interconnected utilities or a shifting of the burden of proof to the merging companies (Klein 1998, pp. 12-15).

State attorneys general have evaluated the competitive effects of a number of electric utility mergers and either participated in regulatory commission proceedings on those mergers or prepared to challenge them in court. Affected parties may also file antitrust suits in an attempt to convince courts to enjoin mergers. For example, Pittsburgh filed an antitrust suit against the Allegheny/DQE merger.

## CONCLUSION

There is no facile "rule-of-thumb" that can be used by policy makers to determine whether a particular merger would be anticompetitive. Some mergers can increase efficiencies without producing undesirable effects on competition. Other mergers can create or increase market power to such a degree that they must be substantially modified or rejected. The lesson is that there is no substitute for careful analysis on the part of policy makers. In a later chapter we examine the implications for merger policy of proposals being considered for federal legislation.



This chapter addresses market power problems that may arise at the retail level, rather than wholesale level, of the electric power supply industry. Retail market power is likely to manifest itself in narrower choices among service and pricing options, inferior customer service, and higher prices for retail electric services for any given level of wholesale prices. For the discussion of these issues, the term *retail marketing* will be used to refer to the supply and marketing to retail customers of services such as procurement of power supplies from the wholesale market or generators, procurement of wires services from transmission and distribution utilities, metering and billing services, demand-side management services, and risk management services. The suppliers of these services are retail marketers, aggregators and energy services companies.

### ORIGINS OF RETAIL MARKET POWER PROBLEMS

As discussed earlier, if entry into a market is “easy” in the antitrust sense, market power is unlikely to be a problem even if the market is highly concentrated. As we stressed, though, to be easy, entry by competitors must be more than simply possible. Entry must be feasible, able to occur on a timely basis, and profitable for the new entrant. As a result, in analyzing competition in retail marketing, it is useful to begin by asking what barriers to entry may exist. For the most part, there appear to be three potential types of entry barriers:

- Barriers that arise from vertical integration of the local distribution utility into retail marketing. Vertical integration may lead to exercise of distribution market power (see Chapter 5 above), improper information sharing and cross-subsidization.
- Barriers that arise from imperfect information and inertia when a market is opened to competition. Even though consumers have a choice of suppliers, they may not switch to a new supplier that offers a superior service, or an equivalent service at a lower price, if they lack information about relative services and prices, and because of inertia.
- Barriers created by government policies, such as provisions for recovery of stranded costs.

In order to demonstrate the importance of such entry barriers in explaining any retail market power problems that may exist, suppose that none of these three types of barriers are present but that nonetheless one company has a very large

market share. Suppose further that this company's share can be explained by the fact that its prices are lower than those of its smaller competitors, and that it is able to charge these lower prices because of various cost advantages. Its cost advantages might be a result of its years of experience in the industry, relatively large scale, or superior management. Should policy makers do anything about this situation? What in fact could public policy accomplish?

Public policies might be adopted to "level the playing field," but policies that would eliminate genuine cost advantages or prevent a seller from taking advantage of such cost advantages would not reduce prices to consumers; the opposite effect on prices is more likely. In short, absent entry barriers, public policies aimed at reducing the market share of the largest supplier may help smaller competitors, but such policies may actually hurt consumers. It is, therefore, important to assess entry barriers.

## ENTRY BARRIERS ARISING FROM VERTICAL INTEGRATION

Competitive concerns raised by common ownership of monopoly distribution utilities and competitive retail marketing companies operating in the same geographic market are discussed in Chapter 5. Government regulators have followed several approaches to dealing with these concerns, including the following:

- *Prohibition of Common Ownership:* Distribution utilities and their affiliates could be prohibited from engaging in sales of power and energy services to retail customers who are able to choose among suppliers and who are located in the geographic area served by the distribution system. For a time, the New Hampshire commission's restructuring plan required that distribution utilities divest marketing services and prohibited distribution companies from marketing power in their franchise territories. These prohibitions would have barred Northeast Utilities from selling power in over half the state, but they were replaced in 1998 by behavioral regulations. In 1998, an Illinois court affirmed a state commission decision rejecting Commonwealth Edison's proposal for an affiliate that would supply energy support services to jurisdictional customers. The commission ruled that if Commonwealth Edison participated in both the energy and energy services markets, it would have an incentive to drive competitors from the latter.
- *Organizational Separation:* A state could require that regulated and unregulated businesses be conducted in separate subsidiaries of a holding company. For example, the subsidiary operating the distribution utility could be prohibited from engaging in retail marketing, which would have to be handled by a separate subsidiary. More limited forms of separation are unbundling of services, accounting separation, and the creation of firewalls between activities within a company. For example, England/Wales and Norway require that

distribution companies unbundle and keep separate accounts for wires services and retail marketing. However, the industry regulator in Norway reported that a number of problems persisted. (See insert.)

- *Prohibitions on Self-Dealing.* In some cases, regulators attempt to deal with competitive problems relating to affiliate abuse and evasion of regulation by prohibiting regulated companies from buying inputs from and selling outputs to unregulated affiliates. For example, a number of states prohibit distribution utilities from purchasing electric power from unregulated affiliated generators, and many states require competitive bidding.

- *Performance-Based Pricing.* Competitive problems relating to cross-subsidization and inappropriate transfer prices in affiliate transactions stem in part from incentives created by traditional cost-based regulation of monopoly activities. These problems may be reduced if regulated prices do not increase when a company's costs increase. A number of states, such as California, have moved away from cost-based regulation to various forms of performance-based regulation. These efforts have parallels in telecommunications, where the Federal Communications Commission and many state regulators are now using "price cap" regulation that breaks the direct link between costs and regulated rates.

- *Regulation of Discriminatory and Other Anticompetitive Behavior:* The default option for attempting to deal with competitive problems raised by common ownership of regulated monopoly and competitive businesses is the proliferation of behavioral regulations, codes of conduct and disclosure requirements aimed at preventing regulated monopolies from behaving anticompetitively toward rivals in competitive markets. Given such regulations, another option is to devote substantial ratepayer and taxpayer resources to monitoring the behavior of vertically integrated companies. An additional option is to subject abuses to

*Most [distribution] utilities tried to establish barriers to traders entering their service area in the form of network restrictions on wheeling. In most cases these restrictions were discriminatory....*

*Some sort of cross-subsidization seems always to be possible in a vertically integrated company, which also works to the disadvantage of traders....*

*A major problem from a regulatory perspective is cross-subsidization from the wires business to final sales. Without this "extra" margin, the final sales business could be a problem for some utilities....*

*The challenge remaining for the reform and the regulator are to restructure the ownership (the wires and final sales) to avoid cross-subsidization and to lower wheeling costs. A major goal remaining is to split the final sales and wires into separate companies. (Moen and Hamrin 1996).*

penalties (beyond disallowances) to increase deterrence. Regulatory approaches not only impose costs but offer mitigation that is incomplete. (See insert).

In fact, thus far states have rarely prohibited affiliates of distribution utilities from engaging in retail marketing (see Jaffe 1998). The principal economic rationale that is typically offered for avoiding structural remedies is that there are economies from vertical integration. In any event, as long as vertical integration is

permitted, regulators will impose numerous behavioral rules in an attempt to limit potential abuses.

With regard to SoCal Edison's purchases from its unregulated generation affiliate at inflated prices during the 1980s (see Appendix B), the California attorney general stated:

*"The fact that this proceeding took two years to get to an ALJ decision illustrates the limits of regulation in detecting and correcting abusive self-dealing practices."*

(Opinion No. 90-507. 1990 Cal. AG LEXIS 57; 73 Op. Atty Gen. Cal. 366; 1991-1 Trade Cas. (CCH) P69, 427).

## USE OF DISTRIBUTION COMPANY ASSETS IN RETAIL MARKETING

This section addresses one specific situation that arises in connection with vertical integration between distribution and retail marketing, namely: the use by a marketing affiliate of assets acquired by the distribution utility in the course of carrying out its regulated business. The discussion here will focus on use of the distribution company's brand name and logo by affiliated marketers. Another example would be use of the distribution company's databases on customer characteristics and consumption patterns.

As a starting point, it is important to recognize that brands are valuable assets that are recognized in stock market valuations. Companies typically build brand names by supplying products that satisfy consumers and by advertising, often at substantial cost. A brand name is valuable when it enables a company to sell more output, other things equal.

Furthermore, brands have important consumer benefits because they help consumers to overcome imperfections of information. The thrust of the substantial economics literature on the function of brands is that companies build brand names and associated reputations in substantial part to reduce search costs for consumers. Brands also serve as guarantees — or bonds — of product or service quality (Frankena 1992). It does not typically make sense for a company to spend millions of dollars building a brand name if the products the company sells will not satisfy consumers. Company investments in building a brand name are likely to be

worthwhile only if the brand helps in attracting and retaining *satisfied*, repeat buyers. If a company delivers shoddy products, it will not only lose customers but damage its brand — in short, it will forfeit its bond.

Because consumers tend to benefit from the existence of brand names, a policy of restricting the use of brand names has the potential of making consumers worse off. The ability to use the existing brand name of a distribution utility is likely to reduce the costs of an affiliated marketer, and also to increase the incentives of such a marketer to satisfy consumers. Those things will tend to benefit consumers. This is not, however, the entire story. A number of complications should be considered in reaching a conclusion regarding appropriate policies toward brands:

- If an affiliated marketer is allowed to use a distribution utility's brand name and logo, and if the distribution utility is subject to cost-based regulation, then the distribution utility may have an incentive to spend as much money as regulators will permit to build the brand name — even if such expenditures do not benefit its jurisdictional customers. Such expenses may be passed along in higher prices for regulated wires services while benefits will accrue to the affiliated marketer. Thus, regulators may have to decide how much advertising, if any, the distribution utility should do.
- If the distribution utility has been guaranteed recovery of its costs and a regulated rate of return for many years, should the value of its brand in new uses accrue to the jurisdictional customers, rather than to the utility's shareholders? In that case, should jurisdictional customers be paid for use of the brand? Downs (1998) reports that the weight of legal authority is that ratepayers have no property interest in a regulated utility's goodwill assets, including its brand and logo. However, at least in some cases, regulators would seem to have a reasonable case that jurisdictional customers have some claim to the value of a brand name.
- There may be a regulatory concern that an affiliated marketer could conduct its affairs in a manner that would reduce the value of a shared brand name to the distribution utility and its jurisdictional customers. Should jurisdictional customers be compensated for this risk?
- Use by a marketing affiliate of the distribution utility's brand name and logo has the potential to deceive consumers. For example, consumers might infer that the affiliated marketer can offer more reliable delivery because of its affiliation with the distribution company, or that the affiliated company is regulated by the state commission. To deal with potential deception, California has mandated disclosure requirements. A utility affiliate cannot use its parent's brand or logo in advertising unless it plainly reveals that the affiliate is not the same company as the utility, that the affiliate is not regulated by the state commission, and that a customer is not obligated to buy the affiliate's product to receive regulated

services from the utility. This would appear to be a reasonable requirement that achieves consumer protection without an outright ban on the use of the brand name.

In the end, theoretical economic reasoning alone appears to be insufficient to reach a conclusion on efficient policies toward affiliate use of brands. Regulators are put in the familiar position of attempting to protect consumers and provide the right incentives to the regulated companies while maximizing the value of the regulated assets. The correct solution to the brand name issue will likely vary somewhat from case to case, depending on the exact arrangements in the market, regulatory history, style of residual regulation and other factors.

### **IMPERFECT INFORMATION AS AN ENTRY BARRIER**

Imperfect information probably enables former monopolists in deregulated markets to charge prices above those that would prevail if consumers had perfect information about the services and prices offered by competitors and if consumers responded quickly and dramatically to differences in relative prices. This is likely to be true in emerging retail electricity markets. The question is what public policy can usefully do about this situation.

Policy makers cannot in fact easily remove the problems that arise from imperfect information and consumer inertia in electric power or other markets. Two policy approaches may make sense. First, in some cases private parties may not have adequate incentives to provide information to consumers, and there may be a role for government in disseminating information. Some state public utility commissions have made consumer education a main feature of restructuring plans of electric utilities. Second, there is a role for government to pass and enforce consumer protection laws designed to prevent deceptive advertising and marketing.

Once again, the experience in telecommunications is relevant. Telephone consumers experienced a troublesome period as independent deregulated payphones were established. Consumers, many of them "transient" customers who were traveling, were accustomed to dealing with familiar monopoly providers when making collect or credit card long distance calls from payphones. New "operator service providers" (OSPs) found they were able to charge exorbitant rates for long distance calls made from these payphones, even as consumers used calling cards issued by their familiar local exchange company.

Information about the rates of OSPs was very difficult to obtain and billing was often delayed months, making it nearly impossible for consumers to understand the new arrangements and to react to prices. The situation was partially ameliorated only after Congress and many state legislatures passed laws requiring various forms of disclosure and refunds of excessive charges. In reaction to the price

gouging, the FCC and many state regulators adopted regulations for OSPs including disclosure requirements such as the requirement of "branding" announcements during the phone call, refunds of exorbitant charges and limits on commissions paid by OSPs to phone location owners. Some state commissions also undertook consumer education efforts of their own. At a time of significant change in this industry when *more* information was needed, imperfect information resulted in price gouging and poor service.

A second telecommunications example concerns long distance service. Although there are many competitors in the long distance industry, regulators have found it necessary to adopt and enforce regulations about how customers can be solicited by long distance companies. Customer inertia, complicated pricing plans and a poor consumer understanding of the rules in this newly competitive market have led to abuses. One purpose of these regulations is, in part, to stem the practice of *slamming*, the unauthorized switching of a consumer's long distance carrier.

In both cases, less efficient providers displaced more efficient ones, to the detriment of consumers. Regulators and legislators adopted and began to enforce new consumer protection rules even as competition was introduced to this market.

## GOVERNMENT POLICIES AS ENTRY BARRIERS

Government policies, such as provisions for recovery of stranded costs, may inadvertently erect entry barriers. For example, Enron recently announced that it would no longer compete for residential customers in California. According to *Foster Electric Report* (April 29, 1998, p. 10), "The company found it too difficult to compete in California under a state law requiring a 10 percent rate cut for all consumers and a competitive transition charge (CTC) designed to recoup California's traditional utilities' stranded costs."

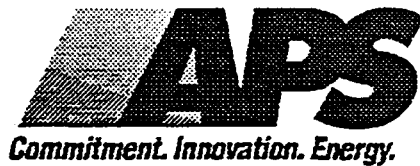
A hypothetical will illustrate this real problem. Suppose a state freezes retail prices at 8 cents per kilowatt-hour (kWh) and requires that consumers pay the incumbent utility 3 cents/kWh for use of its wires and 3 cents/kWh as a CTC if they purchase their electricity from a competing retail marketer. No competing retail marketer is likely to enter the market, because it would not be able to charge more than 2 cents/kWh for unbundled electricity — a price that is not likely to cover its costs. Incumbent utilities do not mind a low unbundled electricity price, since the low price inflates their claimed stranded costs while eliminating competition from retail marketers, and possibly also incentives for competitors to expand generation and transmission capacity (see Pierce 1998).

An implication of this example is that policy makers should attempt to remove avoidable entry barriers and avoid adopting new regulations that will impede entry into retail markets.



Attachment 2

# APS "MUST RUN" GENERATION REPORT



Arizona Public Service Company

## APS "MUST RUN" GENERATION REPORT

### Introduction:

Generation is classified as "Must Run" due to constraints on transmission system. The generation is required to maintain transmission line loading within limits. Limits are based on the most limiting factor of the following:

Thermal  
Stability  
Steady State Voltage  
Dynamic or Post Transient Voltage

In many cases "must run" units can exercise market power in the short term since there is no alternative to mitigate the loading constraints.

This report identifies the APS "must run" units, the transmission limitation and number of hours of "must run".

### Summary of APS "Must Run" Generation:

Listed below are APS units identified as "Must Run" due to transmission systems constraints in selected areas of Arizona transmission network:

- OCOTILLO STEAM 1, 2

"Must Run" due to transmission import limitation into the Valley. Prevents line overload and provides voltage support into the Valley area. Estimated number of hours of "must run" during 1988 is 460 Hrs.  
(See appendix A.)

- WEST PHOENIX COMBINED CYCLE 1, 2, 3

"Must Run" due to transmission, import limitation into the Valley. Prevents line overload and provides voltage support into the Valley area. Estimated numbers of hours of "must run" during 1988 is 460 Hrs.  
(See appendix A.)

## APS "MUST RUN" GENERATION REPORT

Page 2

- YUCCA COMBUSTION TURBINE 1, 2, 3, 4

"Must Run" due to Yuma 69kV import capability limitation via a nomogram. Prevents transformer and line overload. Estimated number of hours of "must run" during 1988 is 2744 Hrs. (See appendix B.)

- DOUGLAS COMBUSTION TURBINE

"Must Run" due to 115kv transmission outage in the area. Serves the load area during the transmission outage. Load is served radially. Thus for a 115 kV line outage, load can only be served by local generation (Douglas CT). Estimated time for "must run" during 1988 is 48min. (See appendix C.)

### Conclusion:

Resource Planning Department should develop the principles for the rates, terms and conditions for APS "Must Run" units under retail direct access on 1/1/99.

P.K., Nov. '97

# APPENDIX A

## APS Valley “Must Run” Generation Analysis



Arizona Public Service Company

## **APS VALLEY "MUST RUN" GENERATION ANALYSIS**

### **Study Objective**

Determine Valley generation "must run" requirements to maintain line flow and voltage profile within Valley import capability.

### **Conclusion**

Valley generation should be classified as "Must Run" due to constraints on the 230KV Valley system.

### **Study Methodology**

This study was performed using two programs: WSCC IPS Power Flow program and GE MAPS cost production model. Most of the simulation was done for 1998 system peak load condition in Arizona and additional scenario cases were run with 2004 transmission system improvement.

Cases with no Valley generation were simulated by importing power from outside of Arizona with 80/20% ratio between California and PacifiCorp respectively.

Valley import capability was calculated by summarizing power entering Phoenix Metro area from four main EHV delivery points. Westwing 500/230KV, Pinnacle Peak 345/230KV, Kyrene 500/230KV and Liberty 345/230KV substations. (see attached map)

Generation Capacity Factor for APS Valley units "must run" was estimated based on hours APS plants (Ocotillo Steam 1,2 and West Phoenix Combined Cycle 1,2,3) needs to be put on-line to alleviate overload or voltage problem on transmission system in the Metro area. Energy output and response factor of each unit was integrated into calculations to determine capacity factor based on summer (3 months) and one year time frame.

## Study Criteria

Import capability into the Valley was determined based on the three limiting factors:

- Thermal (Transmission Loading) - no transmission element will be loaded above 100% of its continuous rating under steady state conditions.

*Note: This transmission loading analysis only evaluated all lines in-service loading problems.*

- Steady State Voltage - voltages should be maintained within their normal operating range at selected buses (1.018 at Pinnacle Peak 230KV) for steady state conditions.

In power flow simulation, base case voltage level was maintained within normal range by switching off reactors, adjusting TCUL transformer taps, switching on capacitors, etc. In cases where voltage level was less than desirable, additional shunt compensation was added to maintain steady state voltage limit.

*Note: This voltage analysis only evaluated all lines in-service conditions.*

- Post Transient Voltage - reactive margin requirement should be maintained at most critical bus for system condition following major disturbance in the area. This margin is obtained by conducting Q-V analysis for N-1 contingency on selected bus. In our study, 350MVAR of reactive margin was used for Pinnacle 230KV bus.

## Study Results

A summary of the power flow, steady state voltage and post-transient studies completed are presented below.

- Results from both MAPS and Power Flow simulation of Valley 230KV transmission system during 1998 without APS/SRP Valley Generation showed that Valley 230KV Import Capacity was 6180MW based on Glendale - Country Club continuous rating. (see table 1, graph 1)

Also, in order to maintain steady state voltage limit and post-transient margin at 6180MW (thermal import limit), additional 260 MVAR of shunt capacitors needs to be added to transmission system at estimated cost of \$2.0 mil. (see table 1, graph 1)

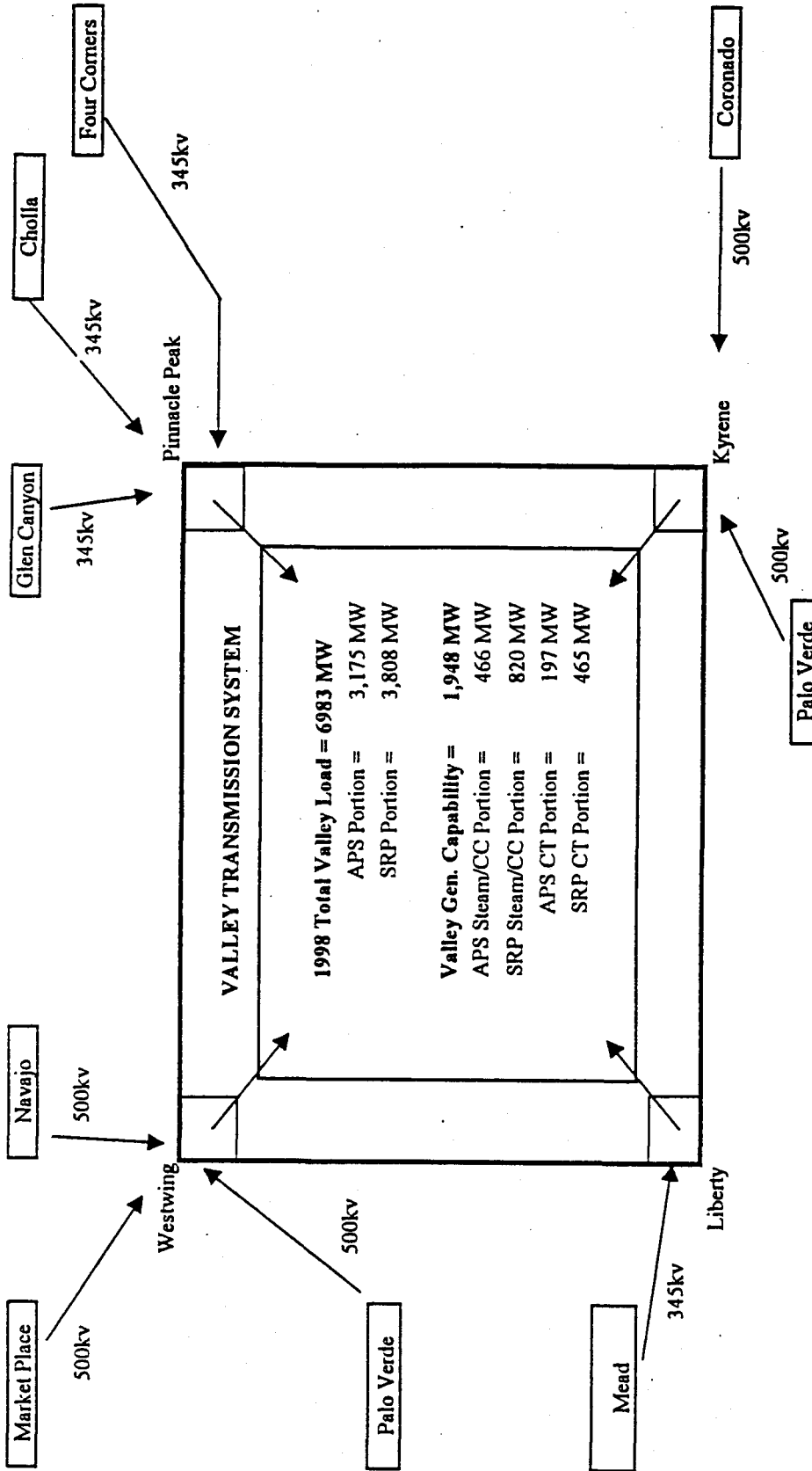
- In order to alleviate the Glendale to Country Club overload, APS Valley generation needs to run for 460 hours during 1998. That translates to a capacity factor of 3.1% a year for West Phoenix Combine Cycle 1,2,3 and 5.3% a year for Ocotillo Steam 1,2. Most of the 460 hours that generation was on line occurred during the summer months that brings up the capacity factor to 12.4% for West Phoenix Combine Cycle 1,2,3 and 21.2% for Ocotillo Steam 1,2. based on total summer hours. (see table 1)
- The need for new generation or transmission in the Valley is estimated to be after 2004. This assumes the current load growth projection, APS/SRP Valley generation, and current import limit into the Valley area. (see graph 1)
- Scenario case analysis without APS/SRP Valley Generation but 230KV transmission reinforcement (at estimated cost \$25 million) showed that Valley 230KV Import Capacity was at 7000MW.

Transmission reinforcement consists of two 230KV transmission lines Westwing to El-sol and White Tanks to W. Phoenix and 750 MVAR of shunt capacitors in the Phoenix Metro area.

In this case, the need for new generation or transmission is estimated to be after 2009. (see table 1, graph 2)

P.K. Oct/97

# IMPORT CAPABILITY INTO THE VALLEY



## Import Limitations:

- Thermal
- Steady State Voltage
- Post Transient Voltage

TABLE 1

**VALLEY 230 KV IMPORT CAPACITY (MW)**

**No Valley Generation**

OPERATING LIMIT	VALLEY * IMPORT MW	LIMITING ELEMENT			HOURS OVER LIMIT	CAPACITY FACTOR	
		PNPK VOLT	PNPK Q-V MARGIN MVAR	THERMAL MW GLND-C.CLUB		WPHX CC1,2,3 YR./SUMMER %	OCT ST 1,2 YR./SUMMER %
THERMAL LIMIT	6184	.993	170	360	460	3.1 / 12.4	5.3 / 21.2
POST TRANSIENT MARGIN	5987	1.007	350	340	550	3.7 / 14.8	6.3 / 25.2
STEADY STATE VOLTAGE	5824	1.018	510	320	650	4.3 / 17.2	7.5 / 30.0

**ELEVATE THE LIMITS:**

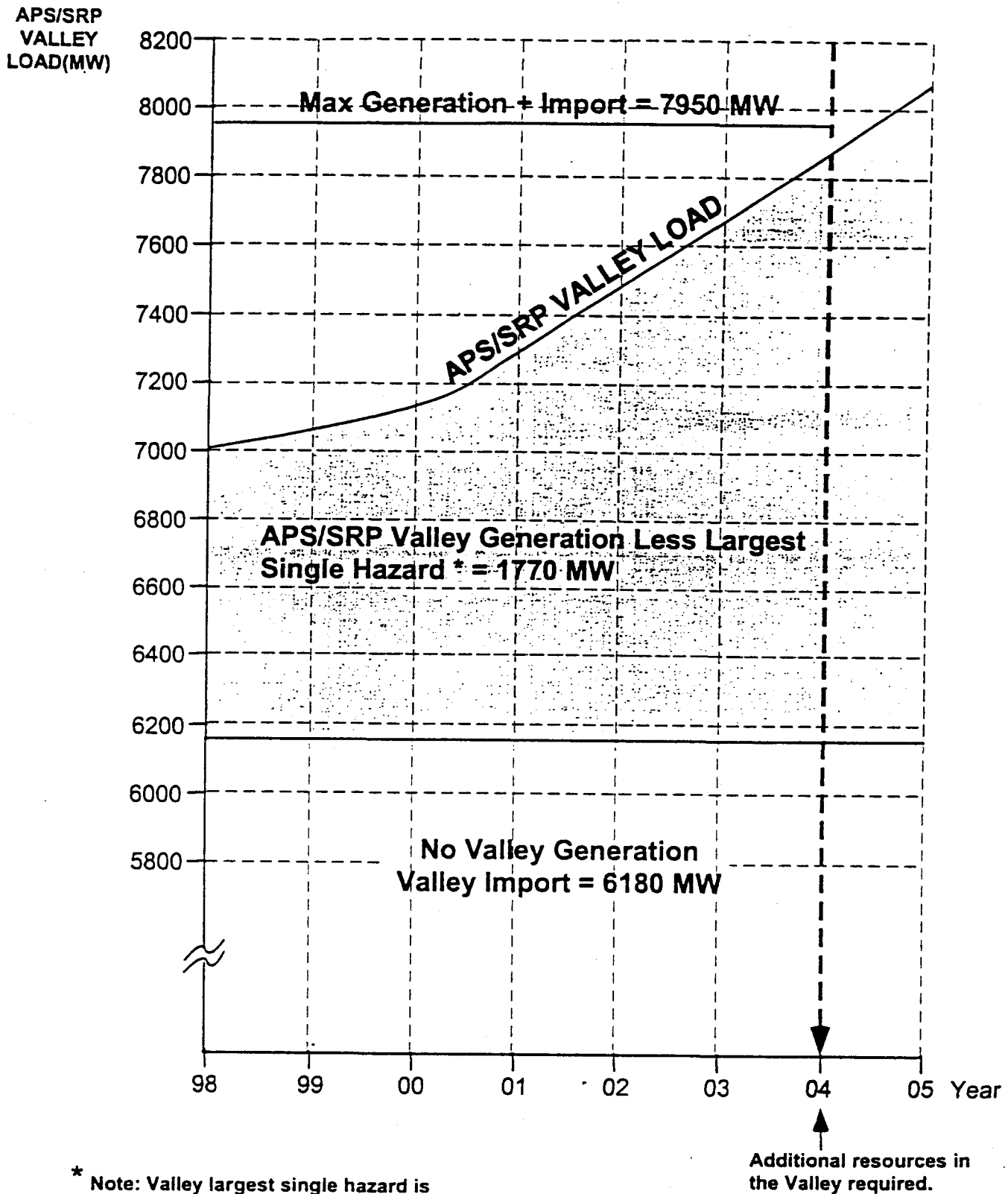
- ◆ STEADY STATE = THERMAL LIMIT → TAKES ADDITIONAL 260 MVAR OF SHUNT CAPACITORS. COST \$2.0 MIL.
- ◆ POST TRANSIENT = THERMAL LIMIT → TAKES ADDITIONAL 200 MVAR OF SHUNT CAPACITORS. COST \$1.7 MIL.

SCENARIO CASE	6915	1.018	210	294	0	0	0
W/2004 SYSTEM ADDITION							
WW - EL SOL 230KV	◆ FOR STEADY STATE LIMIT TAKES ADDITIONAL <u>600 MVAR</u> OF SHUNT CAPS. EST. COST \$ 4.5 MIL.						
WHTX - PHX 230KV	◆ FOR POST TRANSIENT LIMIT TAKES ADDITIONAL <u>750 MVAR</u> OF SHUNT CAPS. EST. COST \$5.5 MIL.						
EST. COST \$20. MIL							

\* Valley Import Capacity updated by 340MW to accommodate Mesa load.

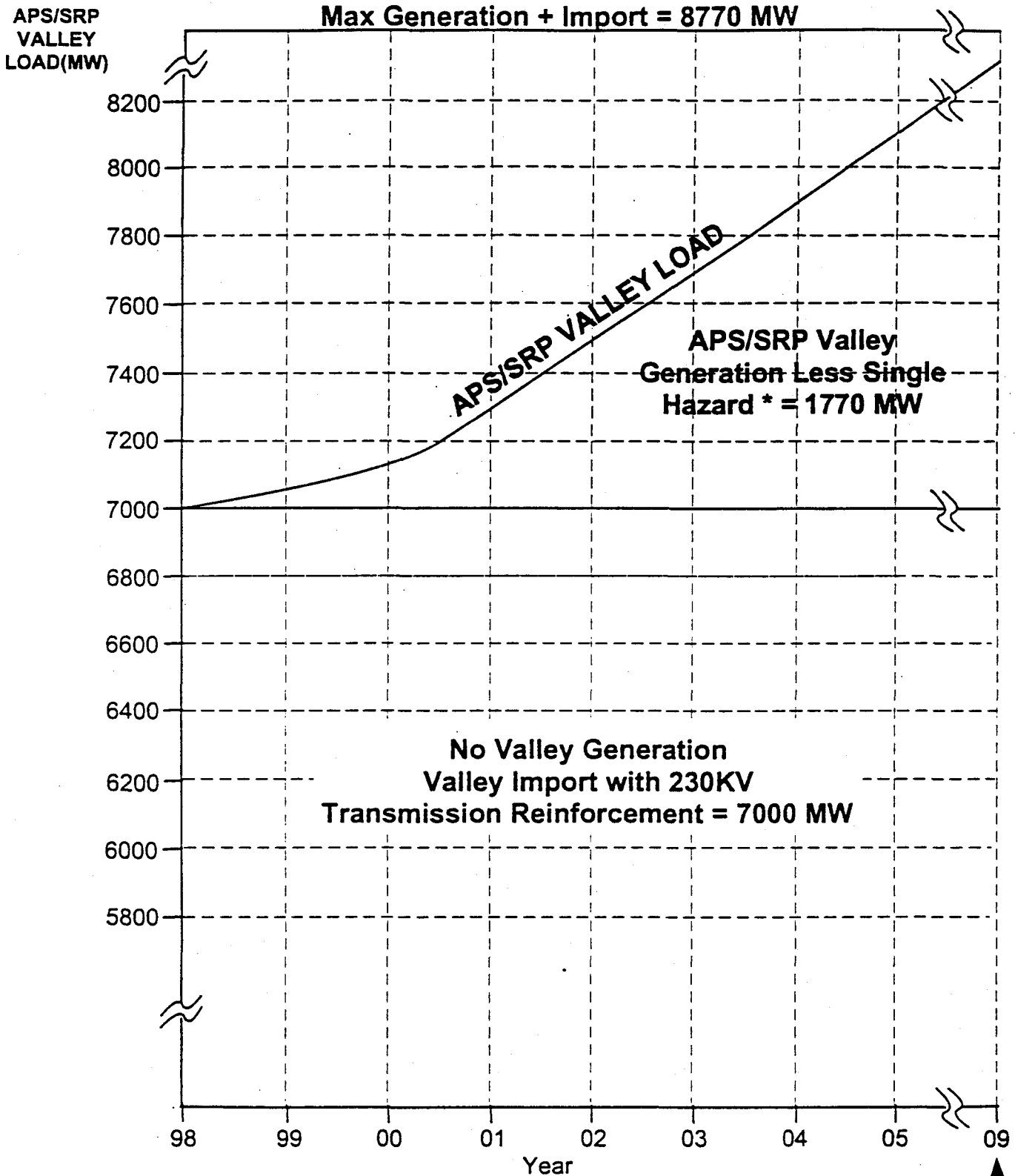
# APS VALLEY "MUST RUN" GENERATION ANALYSIS

## CASE 1 : NO GENERATION OR TRANSMISSION ADDITIONS



\* Note: Valley largest single hazard is Agua Fria #3, 180 MW.

# APS VALLEY "MUST RUN" GENERATION ANALYSIS CASE 2 : NO GENERATION BUT 230KV REINFORCEMENT

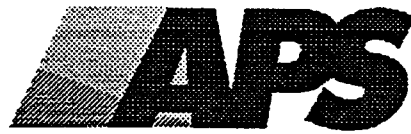


\* Note: Valley largest single hazard is Agua Fria #3, 180 MW.

Additional resources in the Valley required.

# APPENDIX B

## Yuma Area Import Analysis



*Commitment. Innovation. Energy.*

Arizona Public Service Company

## Yuma Area Import Analysis

### Conclusion:

Yucca generation is classified as "Must Run" due to Yuma 69kV import capability limitation.

### 1. Normal Operating Limits:

In the last decade Yuma area experienced substantial load growth in the range of 4% a year from 180MW in the 1987 to 245 MW in 1997.

Yuma area load is served from three main delivery points; Yucca 161/69kV substation, Gila 161/69kV substation and North Gila 500/69kV substation.

Under Normal operating conditions (all lines in service) Yuma import capability is limited to 175 MW of which 140MW is contractual capacity on North Gila 500 kV line and remaining 35MW is WAPA Wheeling. This 175MW import capability reflects also the fact that Axis steam unit capacity of 25MW was recaptured by IID in September 97. (see nomogram 1)

This substantial load growth expansion combined with import capability limit into Yuma area creates a generation "Must Run" scenario for Yucca CT 1, 2, 3, and 4 units.

GE MAPS cost production simulation was done for 1998 system peak load condition in Yuma area to determine amount of hours of "Must Run" generation for Yucca CT's.

As a result Yucca generation needs to run for 2744 hours during 1998 to serve the Yuma area load above 175mw.

### 2. First Contingency Limits:

Yuma 69kV import capability for first contingency condition is defined by Yuma Load vs. Yuma Generation nomogram. (see nomogram 2)

The conditions that determine the boundaries of the nomogram are as follows:

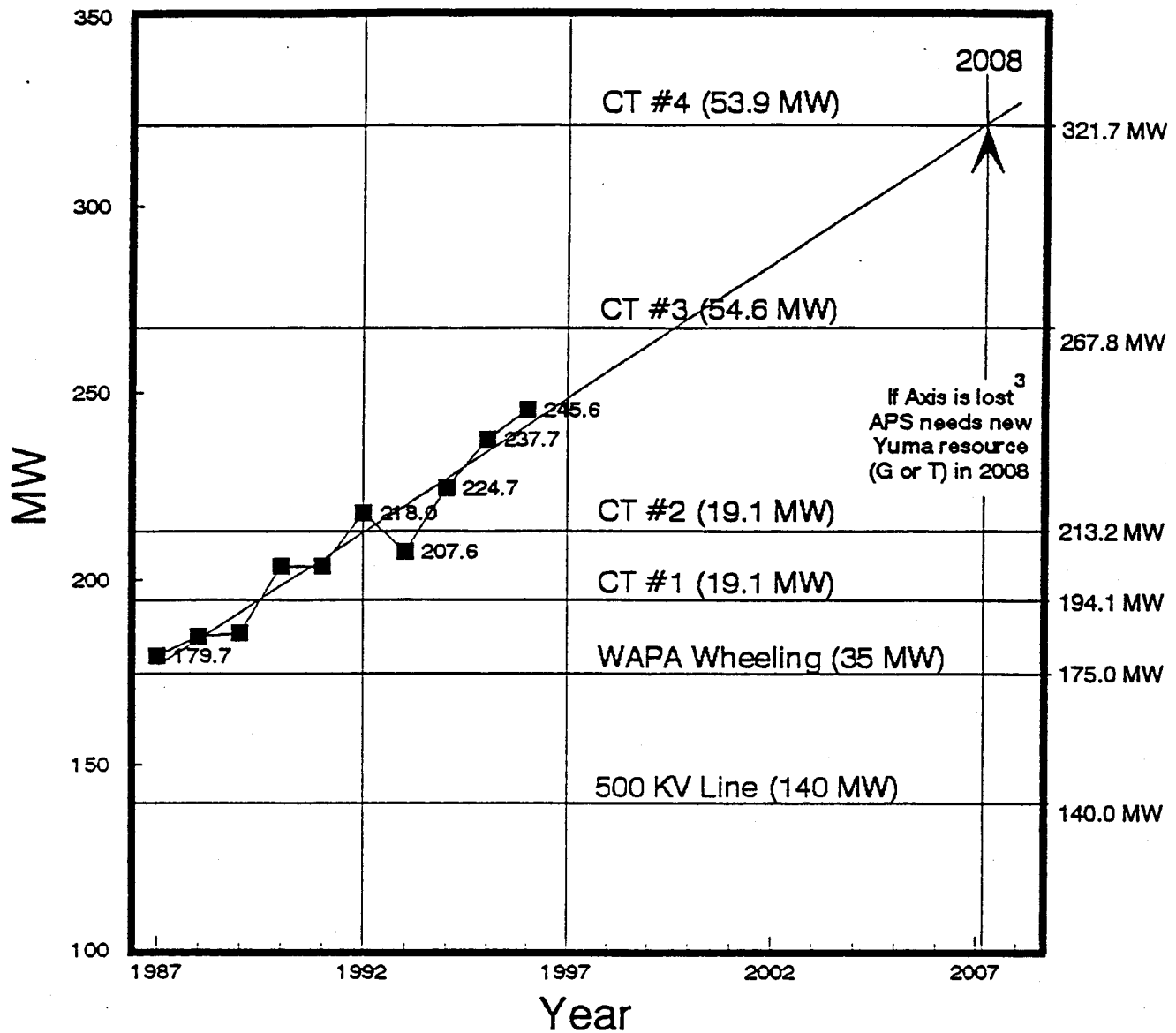
- Critical outage  
Loss of N.Gila 69kV Bus or Yucca 69kV to 32<sup>nd</sup> Street 69kV line.
- Limiting Element  
Overload on Yucca 161/69kV Transformer or 20<sup>th</sup> Street to 32<sup>nd</sup> Street 69kV line.

**Yuma Area Import Analysis**  
**Page 2**

**2. First Contingency Limits (continued):**

It could be seen from the nomogram that Yucca generation is needed to alleviate the Yucca 161/69kV transformer overload for the first contingency (loss of N.Gila 69kV bus) condition . That point on the nomogram corresponds to the Yuma load of 135MW.

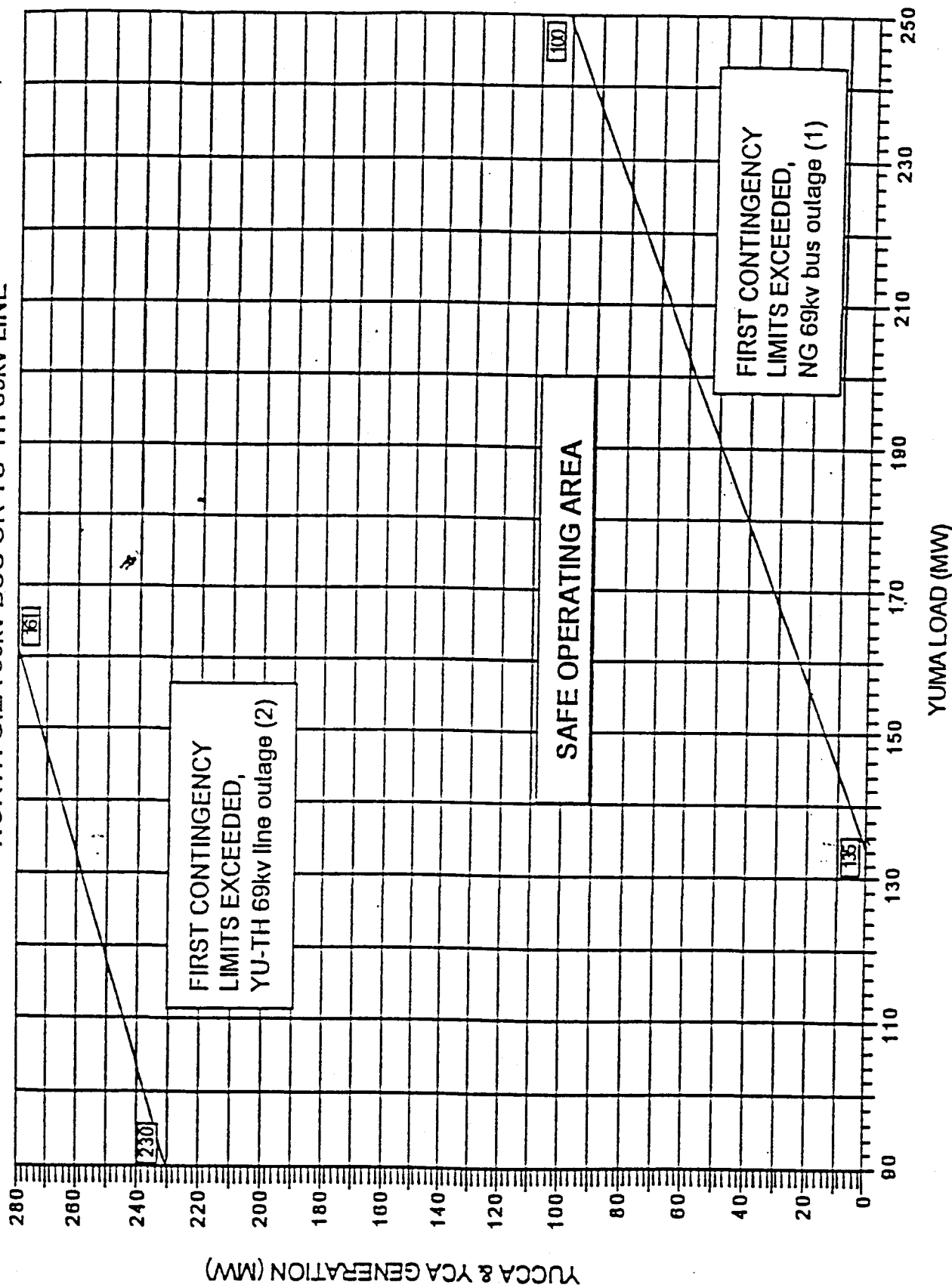
# YUMA AREA LOADS<sup>1</sup> & RESOURCES<sup>2</sup>



## NOTES:

1. 1987 – 1996 Yuma Area historic load from Energy Accounting.
2. Resources assumes APS maintains 25–MW Yuma area reserve margin external to Yuma area per Participation Agreement #2 of the APS/IID Power Coordination Agreement (page 6, Section 4.7). Note: total APS/IID reserve margin = 75 MW.
3. Assumes Axis steam (25 MW) is recaptured by IID effective 8/31/97.

# YUMA LOAD vs. YUMA GENERATION FOR LOSS OF NORTH GILA 69kv BUS OR YU-TH 69kv LINE



- (1) Limiting factor: Thermal YU 161/69kv transformer.
- (2) Limiting factor: Thermal YU 161/69kv transformer.

# APPENDIX C

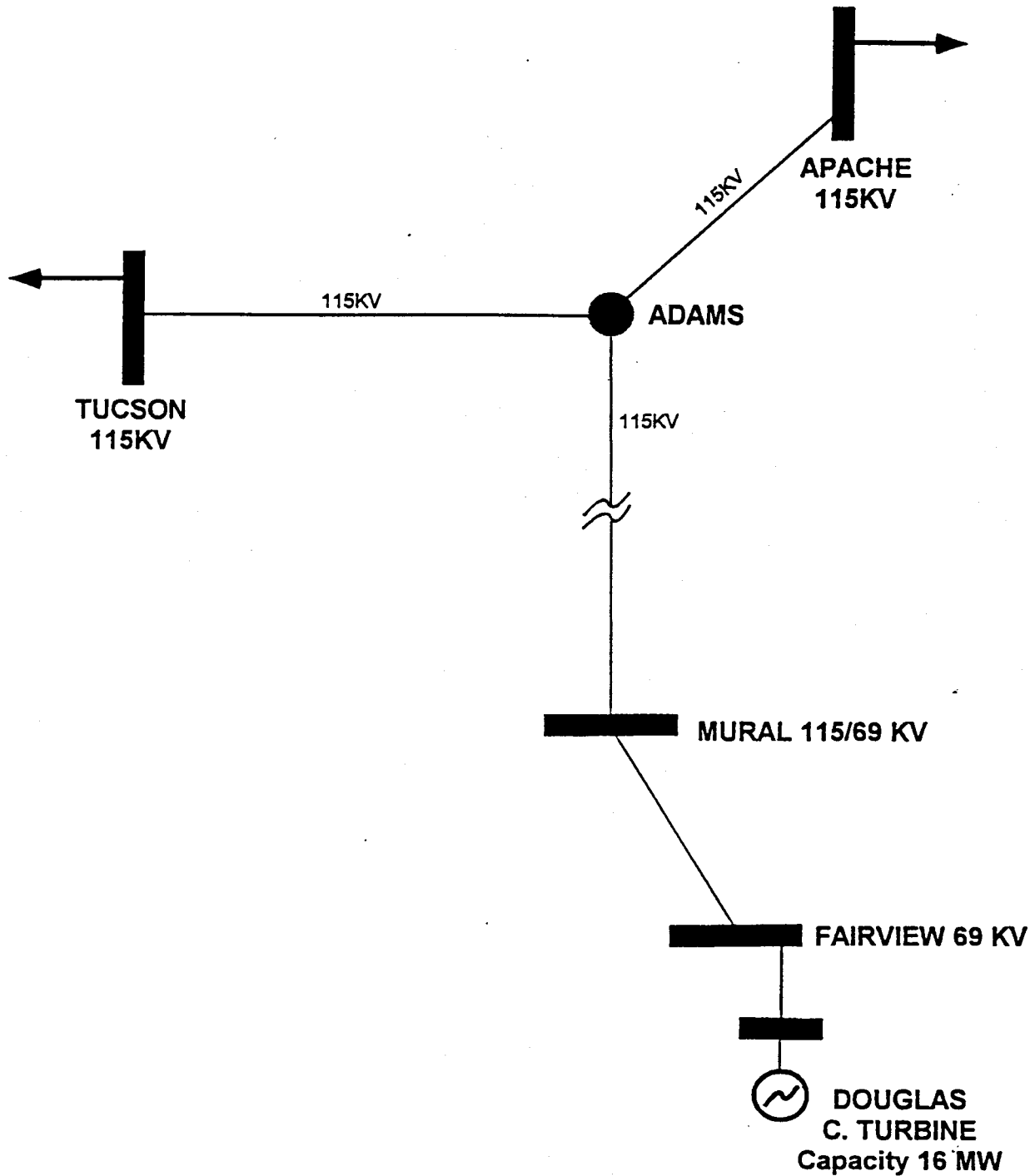
## Douglas Area Analysis



Arizona Public Service Company

# DOUGLAS "MUST RUN" GENERATION

LIMITATION: (OUTAGE OF 115KV LINE AS SHOWN BELOW)



## Attachment 3

### MUST RUN GENERATION REQUIREMENTS

April 17, 1998

- Approximate analysis based on load duration curve analysis.
- Minimum run times and economic considerations will increase hours.
- Most requirements can be met by subset of possible generators.

**Reliability Must Run Generation:** Generation required to meet firm load without violating reliability criteria.

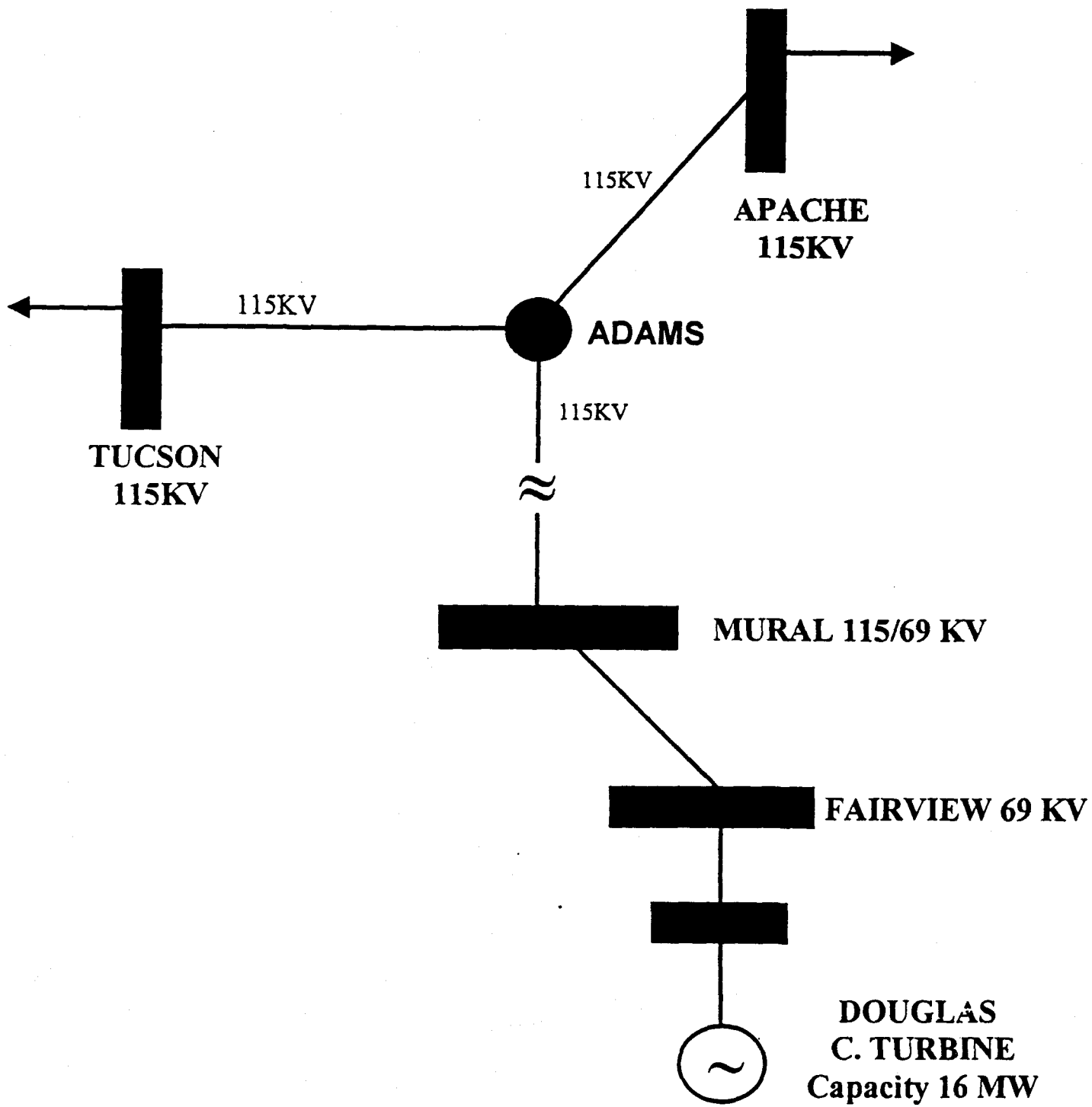
#### Categories:

1. Thermal Overload (may be also considered as necessary to "meet load")
2. Voltage Requirement
3. System Stability
4. Contingency to "meet load"

#### Unit Requirements:

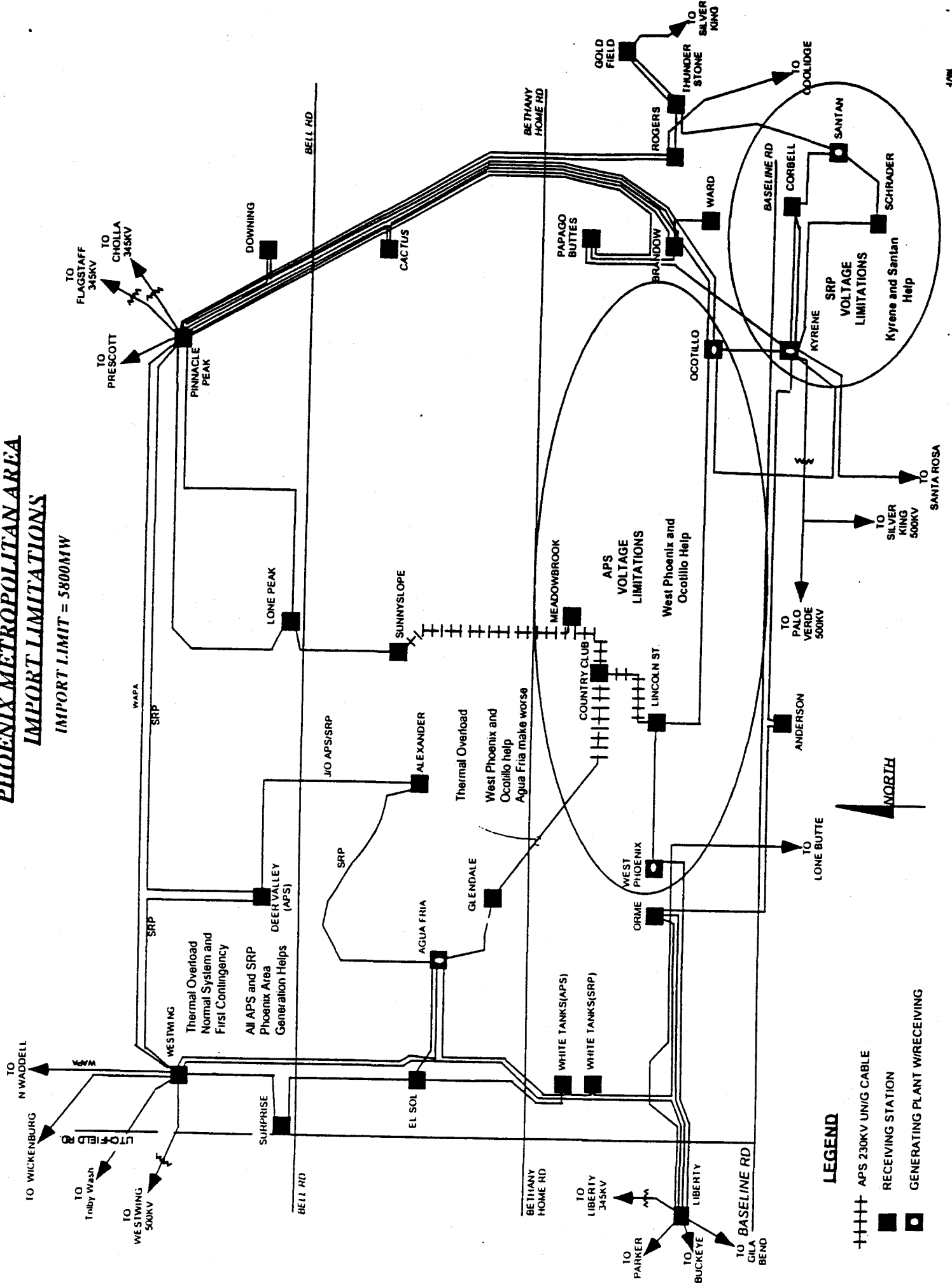
Area	Units	Limitation	Hours
Phoenix	West Phoenix (APS)	Voltage/Overload	447
	Ocotillo (APS)		
	Agua Fria (SRP)		
	Kyrene (SRP)		
	Santan (SRP)		
	Hydro (SRP)		
Yuma	Yucca	Voltage/Overload	1295
Douglas	Fairview	Contingency	1

**DOUGLAS "MUST RUN" GENERATION**  
**LIMITATION: (OUTAGE OF 115KV LINE AS SHOWN BELOW)**

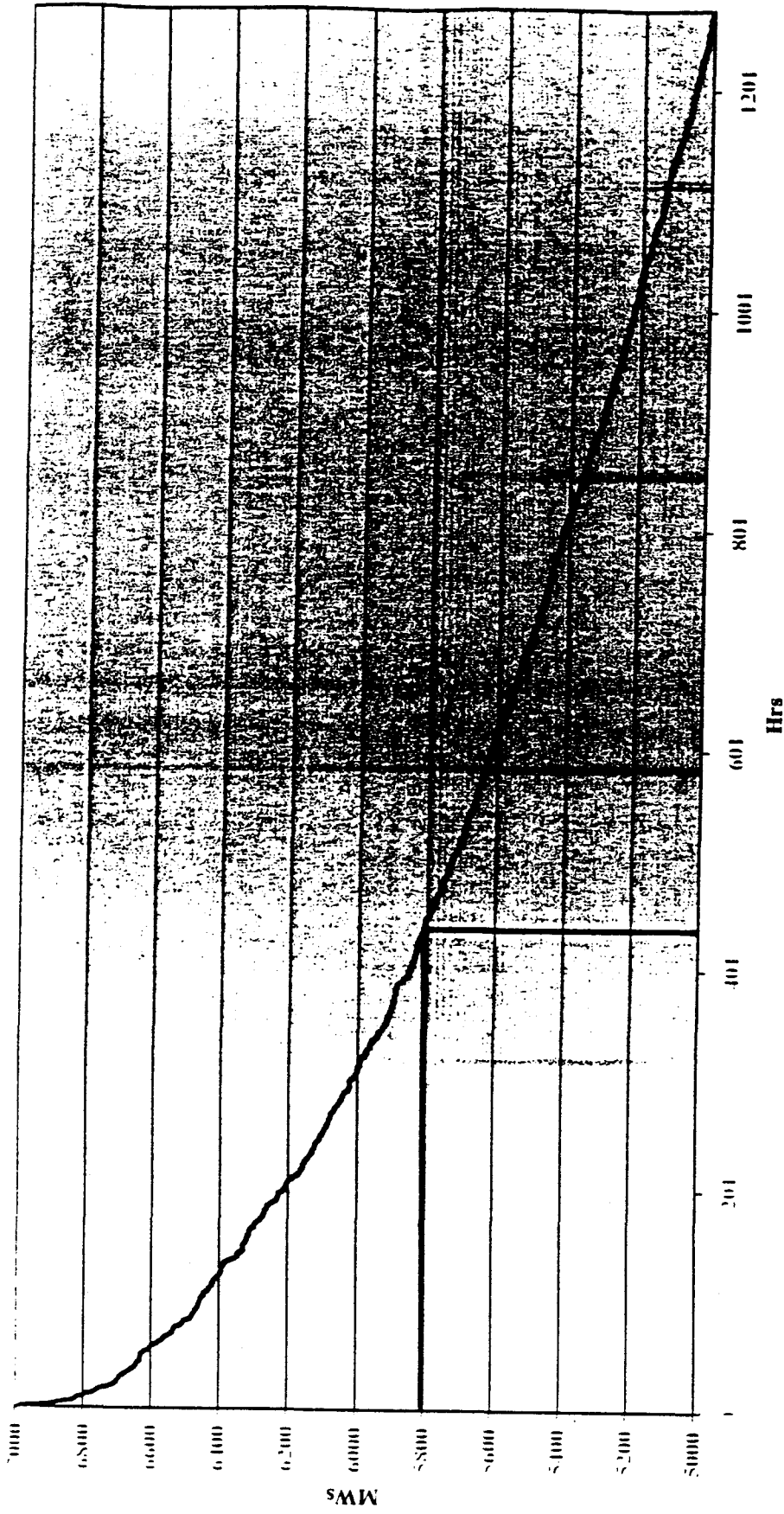


# PHOENIX METROPOLITAN AREA IMPORT LIMITATIONS

IMPORT LIMIT = 5800MW

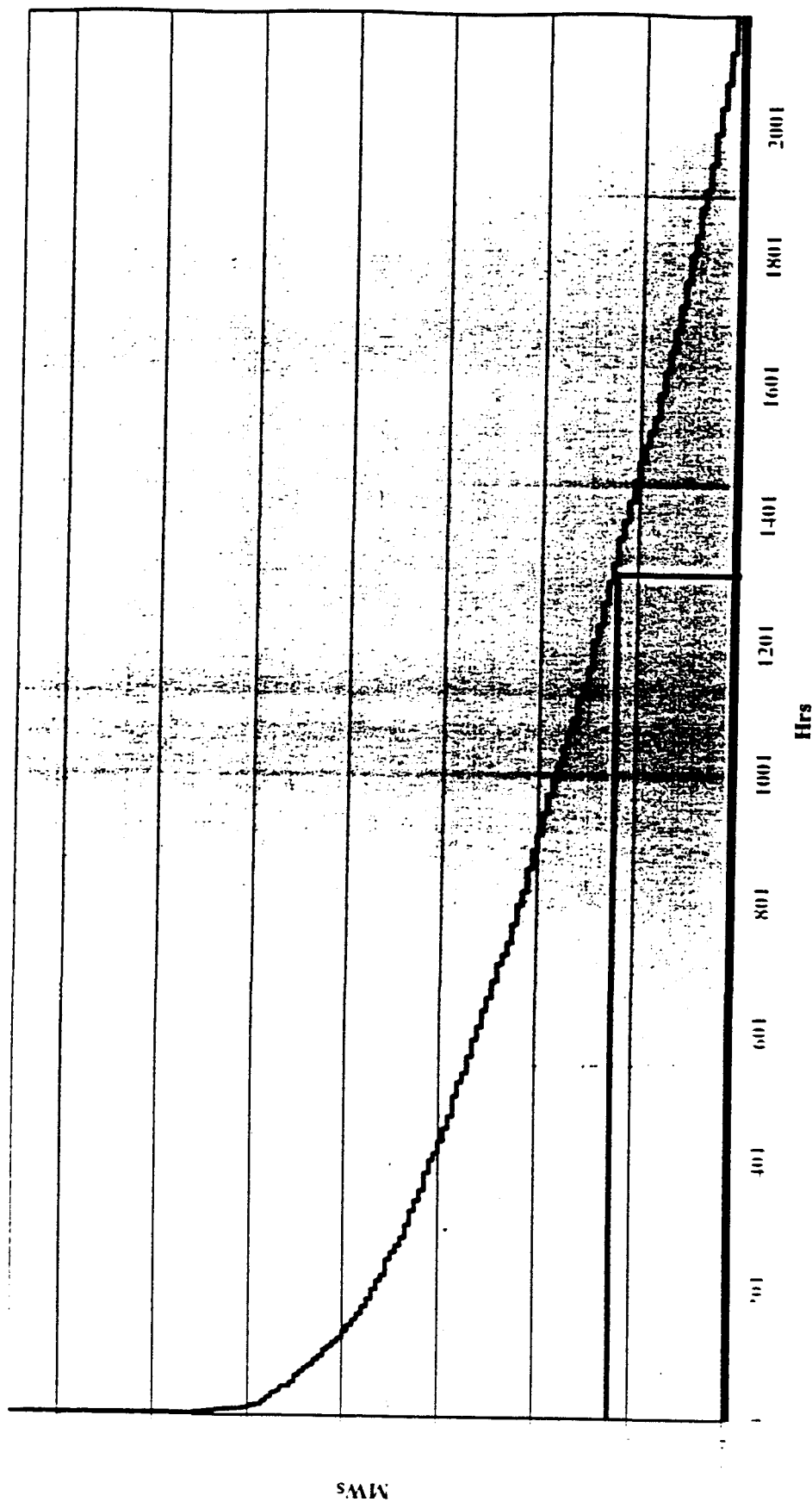


# APS / SRP METRO PHOENIX AREA LOAD DURATION CURVE FOR 1997



Phoenix Area Import Limit = 5800 MW  
Hours load > 5800 = 447 hours

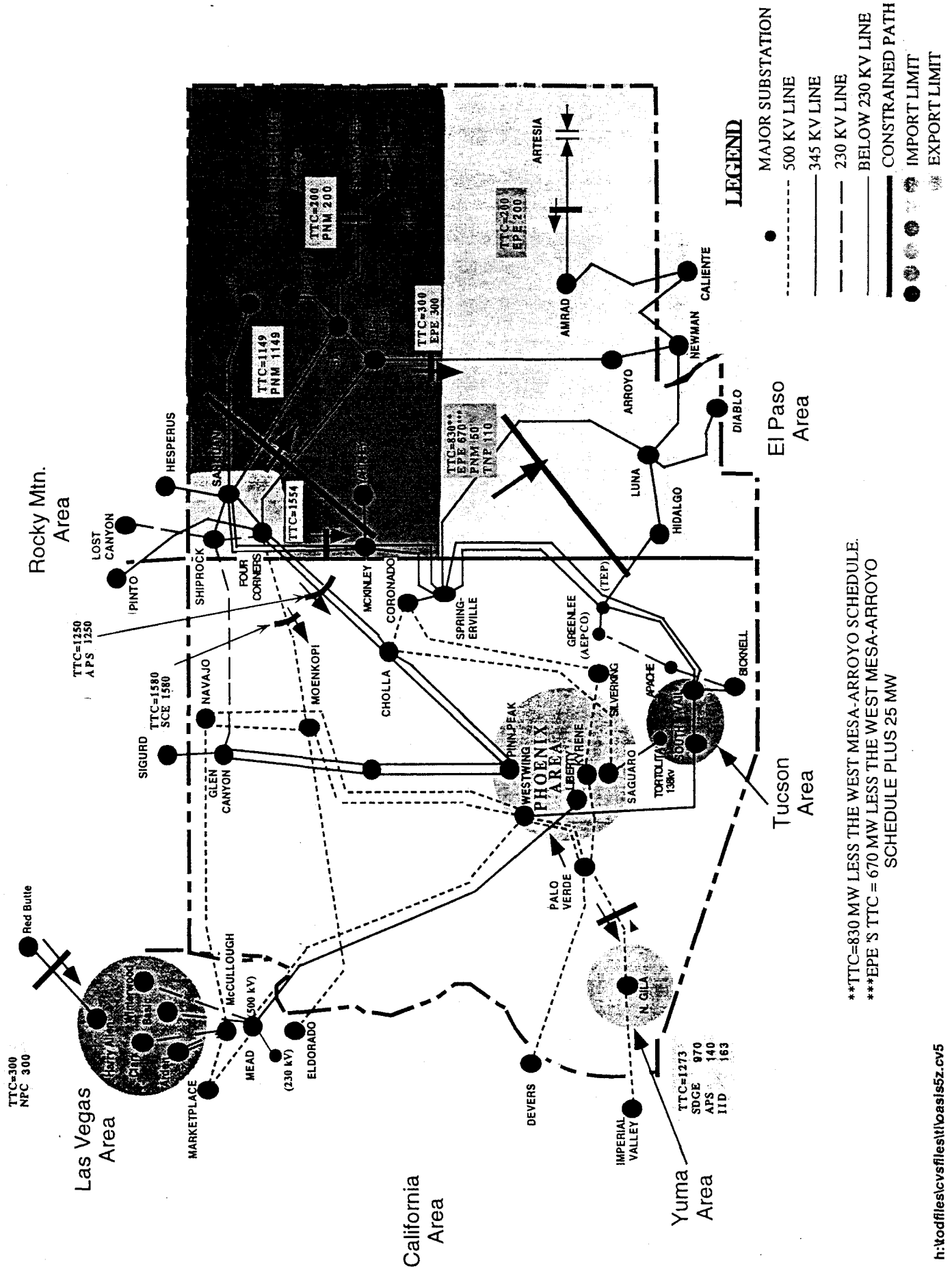
# APS Yuma Area Load Duration Curve for 1997



175 MW Import Limit = 140 MW PV-NG rights + 35 MW Wheeling @ WAPA  
 Hours Load = 175 MW = 1295 hours

D

# CONGESTION PATHS AND CONGESTION ZONES FOR DESERT STAR



\*\*TTC=830 MW LESS THE WEST MESA-ARROYO SCHEDULE.  
\*\*\*EPE'S TTC = 670 MW LESS THE WEST MESA-ARROYO SCHEDULE PLUS 25 MW

# **Planning Work Group Final Report**

*Desert STAR*

Prepared by the Desert Star Planning Work Group

September 12, 1997

The Planning Work Group briefly discussed the need to define the planning and operational seams issues between DSTAR and the distribution entities. The group recommends that a Phase II assignment to the Operations and Planning Work Group should include the development of detailed operating and planning procedures between the distribution entities and DSTAR. To date, the Planning Work Group focused on regional planning requirements of DSTAR, and anticipates addressing local coordination and planning issues in Phase II.

#### **4.3 Seams Issues Associated with Interconnections with Mexico**

In addition to the Seams issues currently under discussion, the Planning Work Group identified a number of other coordination efforts that need to be further addressed in Phase II. DSTAR needs to incorporate transmission systems that interconnect the United States and the Mexico transmission grids. These two transmission grids are asynchronous; therefore, transfer of power over those interconnects (either the United States side or the Mexico side of the interconnections) must operate as an island. To safely incorporate this type of interconnection, DSTAR must have sufficient information as to time of day loads.

Currently, the interconnection facilities between the United States and Mexico are under the regulatory control of the U.S. Department of Energy (DOE) while the jurisdiction for open transmission access is under the jurisdiction of FERC. Therefore, the transmission for foreign sales/purchases to and from Mexico is not specifically under the FERC Open Access tariffs, and FERC may not be able to order transmission access for such sales or purchases. This jurisdictional problem is expected to be addressed at both FERC and DOE in the future. Because of the numerous potential interconnections, DSTAR should actively address interconnection issues with Mexico in Phase II and should consider how WRTA and NRTA are addressing this issue with Canada.

### **5. Transmission Facilities Under DSTAR**

This section outlines the transmission facilities that could come under DSTAR's operational authority depending upon the final ISO requirements and the guidelines developed to select those transmission facilities. The DSTAR planning process and pricing methodology are not necessarily confined to the transmission facilities outlined in this document. For example, the DSTAR pricing methodology may take into account all bulk transmission and sub-transmission assets. The specific details regarding the measure and extent of control that DSTAR maintains over these facilities is covered in the DSTAR Operating Work Group Report. A list entitled A Preliminary Designation of Transmission Facilities for DSTAR Control is attached as Exhibit 4.

#### **5.1 Covered Facilities Guidelines**

The members of the DSTAR Planning and Operations Work Groups followed the guidelines listed below to identify which member transmission facilities qualify for DSTAR control. The Planning Work Group supports the guidelines developed by the Operations Work Group and expanded those guidelines to include the fifth guideline listed below.

**5.1.1** The facilities are critical to maintaining transmission system security.

- 5.1.2 The facilities have a significant and measurable impact on the transmission system transfer capability (e.g., congested paths).
- 5.1.3 The facilities are used to maintain, under today=s paradigm, wholesale transactions<sup>1</sup> in the marketplace.
- 5.1.4 The facilities are generally characterized as 230 kV and above.
- 5.1.5 The DSTAR transmission facilities as a whole are contiguous.

## 5.2 Excluded Facilities

To this point, certain transmission facilities which meet one or more of the aforementioned guidelines have been designated as non-DSTAR facilities by the transmission owner. This is a preliminary list, and is subject to change. The rationale used by the transmission owners to exclude these facilities are as follows:

- 5.2.1 Nevada Power Company
  - radial 230 kV transmission lines interconnecting NPC owned generation to the company=s transmission system
  - 230 kV lines operate as a network with the company=s sub-transmission system, and as such, the lines do not have specific total transfer capability ratings
  - In each case above, the 230 kV transmission lines are nested within NPC=s transmission system.
- 5.2.2 Arizona Public Service
  - 230 kV lines are network lines, and they do not have a specific assigned total transfer capability
  - radial 230 kV transmission
- 5.2.3 Arizona Electric Power Cooperative
  - 230 kV line is a non-commercial, radial line
- 5.2.4 Western Area Power Authority (A Western=s)
  - Western focused on the 500 kV and 345 kV bulk transmission lines between control area.
- 5.2.5 Salt River Project
  - Component of local network providing serving native loads
- 5.2.6 Tucson Electric Power
  - Transformers that connect the Tucson load center to the bulk transmission network.

---

<sup>1</sup> A number of wholesale entities receive service at distribution voltage levels. Those wholesale entities recognize the need to separate operational control and authority between the ISO and the distribution entities; however, their concerns related to fair and nondiscriminatory access from generation sources to point(s) of delivery at distribution voltage levels needs to be assured by DSTAR.

The Planning Work Group recognizes that the list of excluded facilities will require detailed analysis in Phase II. Close coordination between the Pricing and Operations Work Groups will be needed. In addition, there are facilities at voltages less than 230 kV that may be appropriately included in DSTAR.

## **6. Coordination with Pricing/Tariff Group**

### **6.1 Congested Paths**

In accordance with a request from the DSTAR Pricing Work Group, the DSTAR Planning Work Group developed a list of existing or potential congested transmission paths in the southwest (attached as Exhibit 5). The discussions centered on two types of congested paths: actual congested paths (labeled by an A) and scheduling congested paths (labeled by an S).

Actual congested paths include paths where there are actual flow constraints (i.e., technical limitations related to system reliability and/or equipment limitations); scheduling congested paths include paths where existing contractual obligation limit transactions.

## **7. Phase II Issues**

The members of the Planning Work Group agreed that there are many issues that will need to be explored and addressed in greater detail in Phase II.

The Planning Work Group identified some of the issues that will need further exploration and discussion during Phase II of DSTAR. This list is not all inclusive, and may be revised.

- 7.1 DSTAR's role in local transmission planning process
- 7.2 DSTAR's role in the commercial aspect (Integrated Resource Planning)
- 7.3 How to ensure compliance with state and local rules and regulations
- 7.4 DSTAR's role in siting new facilities
- 7.5 Accommodating retail access concerns in the DSTAR planning process
- 7.6 Determine/refine planning process for DSTAR
- 7.7 Formalize planning process
- 7.8 Develop/refine regional reliability criteria
- 7.9 Work out details regarding interactions between DSTAR and other ISOs/control areas
- 7.10 Work with RTG's/SWRTA to revise membership of SWRTA to include all DSTAR stakeholders

Springerville to Luna (345)

A

**Exhibit 5**  
**to**  
**Planning Work Group Final Report**

**A List of Existing or Potential Congested Transmission Paths in the Southwest**

**CONGESTED PATHS**

	<b>S=Schedule</b>	<b>A=Actual</b>
<b>Arizona</b>		
Northeastern Arizona:		
(2) Glen Canyon to Pinnacle Peak (345)		A/S
(2) San Juan to Springerville (345)	S	
(2) Four Corners to Cholla (345)		A/S
Four Corners to Moenkopi (500)		A/S
Shiprock bidirectional Glen Canyon (230)		A/S
Southeastern Arizona:		
Springerville to Coronado (345)	S	
Coronado to Silverking (500)	S	
Greenlee into AEPCO=s 230 kV System		A
Springerville to Vail (345)	S	
Springerville to Greenlee (345)	S	
Greenlee to Vail (345)	S	
Vail into AEPCO=s 230 kV System		A
Westwing bidirectional South (345)	S	
Vail into Tucson network		A
South into Tucson network		A
North Loop into Tucson network		A
Central Arizona:		
Moenkopi to Eldorado (500)	S	
(2) Cholla to Pinnacle Peak (345)		A/S
Westwing (230) into Phoenix network		A/S
Liberty bidirectional Mead (345)	S	
Liberty to Parker (230)	S	
Pinnacle Peak to Davis (230)	S	
Palo Verde to Kyrene (500)	S	
Palo Verde to Devers (500)	S	
Palo Verde to North Gila (500)	S	

**Exhibit 5**  
**to**  
**Planning Work Group Final Report**

**A List of Existing or Potential Congested Transmission Paths in the Southwest**

**CONGESTED PATHS**

	<b>S=Schedule</b>	<b>A=Actual</b>
<b>Colorado</b>		
Southwestern Colorado (Four Corners Area):		
TOT 2A	S	
Rifle to San Juan (345)		
Durango to Shiprock (115)		
Curecanti to Shiprock (230)		
<b>Utah</b>		
Southeastern Utah:		
TOT 2B	S	
Huntington to Four Corners (345)		
Sigurd to Glen Canyon (230)		
<b>Nevada</b>		
Southern Nevada:		
Navajo to McCullough (500)	S	
McMullough into NPC network (230)	S	
Mead into NPC network (230)	S	
TOT 2C	S	
Redbute to Harvey Allen (345)		
<b>New Mexico</b>		
Eastern New Mexico:		
Blackwater bidirectional B-A (345)		A/S
Eddy County bidirectional Amrad (345)		A/S
Northern New Mexico:		
Northern New Mexico Imports (NNMI)		A
San Juan to Ojo (345)		
San Juan to BA (345)		
Four Corners to West Mesa (345)		
Four Corners to Gallegos (230)		
Gallegos Transformer (230/115)		
McKinley to YahTaHey (345/115)		
West Mesa to Arroyo (345)		
West Mesa to Belen (115)		
Northeastern New Mexico Imports (NAS)		A
Ojo Transformer (345/115)		
Norton Transformer (345/115)		
Norton to Algodones (115)		
B-A to ETA (115)		
B-A to Zia (115)		
Central New Mexico:		
West Mesa bidirectional Arroyo (345)	A/S	
Greenlee to Hidalgo (345)		A

*OPERATIONS/IMPLEMENTATION*

*WORKGROUP*

*STATUS REPORT*

*DSTAR*

*MAY 1998*

## *TABLE OF CONTENTS*

I.	EXECUTIVE SUMMARY _____	3
II.	CONSTRAINED PATHS/CONGESTED ZONE MAP _____	5
III.	CONSTRAINED PATHS DATA _____	6
IV.	SUMMARY OF MUST-RUN UNITS _____	9
V.	IMPLEMENTATION MODELS _____	10
VI.	DSTAR CONTROL AREA OPERATIONS DISCUSSIONS_	12

## **I. EXECUTIVE SUMMARY**

### **A. CONSTRAINED PATHS/CONGESTED MAP ZONES**

Eight zones have been identified for the DSTAR region. The zones are:

- 1) Northern New Mexico
- 2) Southern New Mexico/El Paso
- 3) San Juan/Four Corners/Shiprock
- 4) Phoenix, AZ
- 5) Tucson, AZ
- 6) Las Vegas, NV
- 7) Yuma, AZ
- 8) Remaining Arizona

Zones #3 is an "export" congestion zone. Zone #8 is not congested and the remaining zones (to load centers) have "import" constraints.

### **B. CONSTRAINED PATHS DATA**

The constrained path list was developed from a combination of:

- 1) Known Thermal Line Constraints
- 2)  $ATC = 0$
- 3) Must-run Unit Operation

Phoenix, Las Vegas, Tucson and El Paso require local generation due to import limitations into the load centers on transmission circuits internal to their load centers. Albuquerque has voltage limitations for N-1 conditions on the San Juan/Four Corners path.

The San Juan/Four Corners/Shiprock center has export constraints to Albuquerque, Cholla, Moenkopi and Glen Canyon.

### C. MUST-RUN GENERATION

Phoenix, Las Vegas, Tucson and El Paso each have units that must be operated to serve load in the high load seasons. Following is the must-run relative magnitude:

Phoenix:	450 Hour/Year
Las Vegas:	Not Verified
Tucson:	81% of the Days
El Paso:	Minimum of 3 Units Must Run All Year

### D. IMPLEMENTATION MODELS

Four models are recommended to be analyzed for DSTAR as:

- 1) a Scheduling Administrator
- 2) a Security Coordinator
- 3) a Hybrid-Control Area Operator
- 4) a Single Control Area Operator.

### E. DSTAR CONTROL AREA OPERATIONS

Discussion early in this Stage of Phase II, a poll was taken to obtain a sense as to where the member DSTAR Control Area Operators stood on relinquishing their Control Area Operation to DSTAR.

Following are the results of the poll:

<u>STATUS</u>	<u>MEMBER</u>
Continued CAO's	SRP, WAPA, EPE
Considered Turn-Over of CAO's	APS
Undecided	PNM, NPC, TEP
Evaluating CAO's	PEGT

## **II. CONSTRAINED PATHS/CONGESTED ZONE MAP**

### **III. CONSTRAINED PATHS DATA**

**DSTAR O/I WORKING GROUP  
Congested/Constrained Interface:**

Company:	Path:	Nature of Congestion:
AEPCO	Westwing/Vail 345Kv TTC=161MW	0 ATC all year, committed use.
APS	4-Cnrs/Cholla 345kv TTC=1250MW	0 ATC for 742 hrs/yr, 62 ATC for 1550 hrs/yr
	Palo Verde-Westwing TTC=1318	0 ATC for 318 hrs/yr 66MW ATC for 2294 hrs/yr
	Palo Verde-N. Gila TTC=140MW	0 ATC for 2968 hrs/yr 7MW ATC for 4294 hrs/yr
El Paso	West Mesa-Arroyo 345kv TTC=300MW	0 ATC for 7000 hrs/yr
	Sprvl-Luna 345 kV Greenlee-Hidalgo 345kv TTC=519MW	0 ATC for 5500 hrs/yr
NPC	Red Butte-Harry Allen TTC=300MW	0 ATC for 3384 hrs/yr
	Harry Allen-Mead TTC=300MW	0 ATC for 3384 hrs/yr
	Harry Allen-McCullough TTC=300MW	0 ATC for 3384 hrs/yr
	Namajor-McCullough TTC=360MW	0 ATC for 1248 hrs/yr
PNM	San Juan-Albuquerque	0 ATC all year, committed use.
SRP	4 Cnrs-Coronado TTC=50MW	0 ATC all year, committed use.
	4 Cnrs-4Cnrs TCC=50MW	2MW ATC all year
	NV-Moenkopi- McCullough	0 ATC all year, committed use.

TTC=344MW

Palo Verde-Hayden  
TTC=95MW

13MW ATC Jul-Sep

**DSTAR O/I WORKING GROUP**  
**Congested/Constrained Interface Con't:**

	Palo Verde-Pinnacle Peak	13MW ATC Jul-Aug
	SilverKing-Hayden TTC=95MW	21MW ATC May-Aug
TEP	(2) San Juan to McKinley 345kV TTC=1554MW	0 ATC all year, committed use.
	Sprvl-Coronado 345kV TTC=672MW	0 ATC all year, committed use.
	Sprvl-Vail 345kV TTC=666MW	0 ATC all year, committed use.
	Sprvl-Greenlee 345kV TTC=745MW	0 ATC all year, committed use.
	Greenlee-Vail 345kV TTC=896	0 ATC all year, committed use.
	Westwing Bidirectional South 345kV TTC=511MW	0 ATC all year, committed use.
	Vail into Tucson Network TTC=1338MW	0 ATC all year, committed use.
	South into Tucson Network TTC=672MW	0 ATC all year, committed use.
	North Loop into Tucson Network TTC=672MW	0 ATC all year, committed use.
WAPA	Data Not Confirmed	

#### IV. SUMMARY OF MUST-RUN UNITS

Phoenix, Las Vegas, Tucson and El Paso each have units that must operate to serve load.

The following summarizes the Must-Run relative magnitude:

Company	Description
AEPC	One of the units at Apache must run all year
APS	Metro-Phoenix units must run approximately 447 hrs/yr when valley load exceeds 5800MW Yuma - Douglas - N-1 contingency  Douglas - N-1 contingency
El Paso	Minimum of 3 units must run all year Rio Grand Plant must run to maintain import capability which is 100% of the time in the summer months
NPC	Data not confirmed
PNM	No must-run units
SRP	Metro-Phoenix units must run approximately 200-400 hrs/yr when valley load exceeds 5800MW
WAPA	Data not confirmed

## V. IMPLEMENTATION MODELS

Four models are recommended to be analyzed for DSTAR implementation consideration: The models were suggested as a result of the Pricing WG's "Economic Analysis" Subgroup efforts.

### DSTAR Implementation Options Briefs:

#### Option 1: ISO as **Independent Scheduling Administrator**

##### Market Structure:

- WSCC Security Coordinator hosted by WAPA
- Regional OASIS hosted by ISO
- Congestion Management protocols implemented by ISO
- Scheduling Coordinator infrastructure implemented
- Control Area Operators continue to operate the grid.

##### Characteristics:

The ISO will rely heavily on well defined and well developed Protocols/agreements which would integrate all of the market structure functions listed.

##### Critical Path Implementation Issue:

- Operation in 12 months
- Regional Transmission Tariff
- Congestion Management Protocols/Agreements.

#### Option 2: ISO as **WSCC Security Coordinator**

##### Market Structure:

- WSCC Security Coordinator hosted by ISO
- Regional OASIS hosted by ISO
- Congestion Management hosted by ISO
- Scheduling Coordinator infrastructure implemented
- Control Area Operators continue to operate the grid

##### Characteristics:

- The ISO would consolidate the OASIS and the Security Coordination functions but would have to develop protocols and agreements such that the ISO, Scheduling Coordinators and Control Area Operators would be integrated.

Critical Path Implementation Issue:

- Operational in 18 months
- Liability Insurance

Option 3: ISO as a **Partial-regional Control Area Operator**

Market Structure:

- WSCC Security Coordinator hosted by ISO
- Regional OASIS hosted by ISO
- Congestion Management hosted by ISO
- Scheduling Coordination infrastructure implemented
- Partial Regional Control Area Services hosted by ISO

Critical Path Implementation Issue:

- Operational in 48 months
- Liability Insurance
- EMS Implementation

Option 4: **Independent System Operator**

Market Structure

- WSCC Security Coordinator hosted by ISO
- Regional OASIS hosted by ISO
- Congestion Management hosted by ISO
- Scheduling Coordination infrastructure implemented
- Control Area Services hosted by ISO for entire DSTAR Region

Characteristics:

The ISO would meet all of the FERC independence principles with the addition of operating as a single control area. The ISO would require the development of protocols and agreements for the Scheduling Coordinators. The ISO would also facilitate the Ancillary Services Requirements.

Critical Path Implementation Issues:

- Operations in 48 to 60 months
- Liability Insurance
- EMS Implementation

## VI. DSTAR CONTROL AREA OPERATIONS

One conclusion that can be inferred from a March 2, 1998 poll, DSTAR will not be a single Control Area Operation in the inception stages.

However, it may be possible the DSTAR would offer Control Area Services for part of the region. This would be described as a Hybrid - Control Area Operation (Option #3, Section V.)

Following is a result of the poll taken on March 2, 1998:

<u>STATUS</u>	<u>MEMBER</u>
Continued CAO's	SRP, WAPA, EPE
Considered Turn-Over of CAO's	APS
Undecided	PNM, NPC, TEP
Evaluating CAO's	PEGT

**Subject: DSTAR O/I WG 09Apr98 Meeting Notes, Tucson**

**Date:** Fri, 10 Apr 1998 10:37:19 -0700

**From:** "David E. Murphy" <demurphy@srp.gov>

**Organization:** srp

**To:** <desertstar-operations@listerv.azstarnet.com>, <desertstar-tariff@listserv.azstarnet.com>

DSTAR O/I Meeting Notes of 09Apr98, TEP

**Action Items:**

- o All: Review/Comment on the 06Mar98 Draft of Congestion Management Outline (for 4/23 Joint Mtg)
- o WAPA: Provide Congested Path Data for WAPA's system
- o WAPA: Provide Must-run data for WAPA's system
- o APS/SRP: Commercial-significance model Metro-Phx must-run
- o SRP: Phase II Implementation Plan update
- o APS: Update Constrained Paths/Congestion Zone Map
- o WAPA: Must-Run Category Strawman

**Meeting Information:**

- o 23Apr98: Joint Pricing/Operations WG Meeting  
Hosted by El Paso Electric, 123 W Mills, El Paso  
Topic: Congestion Management and Pricing Zones
- o 07May98: Joint Pricing/Operations WG Meeting  
Hosted by APS, Lincoln/3rd Ave, Phoenix  
Topic: Must-Run Generation
- o 21May98: Operations WG Meeting  
Hosted by PNM, (tbd), Albuquerque  
Topic: Finalize Implementation Plan
- o 04Jun98: Operations WG Meeting  
Hosted by SRP, 6504 E. Thomas Road  
Topic: Review Draft of Stage I Operation's Report
- o 21Jul98: Operations WG Meeting  
Hosted by NPC, (tbd), Las Vegas  
Topic: Finalize Stage I Operations's Report

**Conclusions:**

- o Finalized Pricing Zones based on "physical system constraints"
- o DSTAR functions identified in Phase I Report continue to be valid for requirements for a FERC approved ISO.

**Discussion:**

- o Implementation Plan Update:  
Steering Committee direction (4/1/98) meeting was to develop a phase-in implementation plan for DSTAR. The discussion concluded with the basic functions identified in Phase I remain valid for implementation strategy of DSTAR to gain FERC approval.

The Scheduling/OASIS modules should be rolled out together and the Security Coordinator and Congestion Management modules should be rolled out together.

The FERC ISO conference (next week) may have some impact on how FERC views ISO in the future. DSTAR needs to take into account any changes to FERC's ISO principles as a result of this conference.

The market place will indicate change towards achieving the ISO principles. OASIS/Schedulings should be implemented first with Security Coordination and Congestion Management following.

o Must-Run Generation:

There was much discussion/debate regarding Must-Run status. It is recognized that there are at least three categories of must-run generation status and further splits within each of the broad categories. It is also recognized, from a pricing perspective, that must-run units have varying characteristics in the different load centers of the DSTAR region. It is also recognized that there could be pricing variations depending on whether the view is from a Wholesale or Retail open access perspective. Following is a summary, first, of the Must-Run Categories and Second, the DSTAR load center differing must-run characteristics.

Must-Run Categories:

- o Regulatory  
(para-phrasing from 26Feb98 O/I WG mtg notes)
  - Hydro Units due to water regulatory issues
  - Nuclear due to NRC issues
- o System Dynamics
  - Support load-center import capability
  - Increase EHV path TTC
  - Load serving
  - Line loading relief
  - Cover N-1 contingencies
  - Spinning/Non-spinning Reserves
  - Regulation
  - Black start
- o Voltage Support
  - Support Voltage profile during at high load periods

WAPA will develop a strawman to further define "must-run" categories.

Must-Run Load Center Characteristics:

- o Albuquerque
  - Units increase load serving capability for Albuquerque.
- o El Paso
  - 3 units must run all year to serve load and to "keep the lights on" in El Paso
  - Rio Grand unit must run summer months to maintain the import capability.
- o Las Vegas
  - Serve load due to line load limitations on the lower EHV system into Las Vegas
- o Phoenix(Metro-region)
  - Serve load due to line load limitations on the lower EHV system into Metro-Phoenix.
  - Voltage Stability at high loads
- o Tucson
  - EHV import limitation
  - Voltage Support
  - Contract limitation
- o Yuma
  - Import limitation

o Pricing Zones:

Based on a combination of Must-Run data and physical EHV line loading limitations, the following pricing zones are recommended for analysis for further "Commercial-significance" analysis:

- o Las Vegas

- Driver: Must-Run Units in Las Vegas to relieve lower voltage EHV ties to the city load.
- o Phoenix
  - Dirver: Must-Run Units in Metro-Phoenix to relieve lower voltage EHV ties to the city load. APS/SRP are to get together and follow up on a analysis model that will be used in all of the pricing zones to determin if these zones are "commercially" significant.
- o Tucson
  - Driver: Must-Run Units in Tucson to relieve EHV lines to Tuscson.
- o Yuma
  - Driver: Must-Run unit in Yuma due to contract limits the tie to Yuma.
- o El Paso
  - Driver: a) Must-run to serve load  
b) Must-run to keep increase TTC for NM EHV lines
- o San Juan/Four Corners/ShipRock
  - Driver: Identified as an "Export Zone" due to line load limits on the FourCorners-Cholla path.
- o DSTAR Regional (Excluding Specific Zones above):
  - The rest of the DSTAR region outside of the zones identified above would be a single pricing zone.
- o Congestion Management Modle:

Lots of Discussion/Debate on the proposed congestion management model. All have the assignment to review the doument futher and be prepared to comment at the 4/23/98 Joint Pricing & Operations Meeting in El Paso.

The model on the table now features FTR's (Firm Transmission Rights). There are 3 tiers of market involvement regarding the FTR Model:

1. Annual Auction of FTRs
2. Day-ahead market of unscheduled rights
3. Secondary market FTR trading via an FTR Exchange

It has been suggested that the FTR model is "superior" to the FERC recommended OASIS process of dealing with descriminatory access to the transmission grid.

Please, if I have misrepresented anything in these notes, let me know.  
Thank you for your participation.

**Subject: DSTAR Regional Congested Transmission Paths****Date:** Mon, 6 Apr 1998 15:54:24 -0700**From:** "David E. Murphy" <demurphy@srp.gov>**Organization:** srp**To:** <desertstar-operations@listserv.azstarnet.com>,  
<desertstar-tariff@listserv.azstarnet.com>

## Summary Operational Data

## Re: DSTAR Regional Congested/Constrained Interfaces

Company:	Path:	Nature of Congestion:
=====	=====	=====
AEPCO	Westwing/Vail 345kV TTC=161MW	0 ATC all year, committed use
APS	4-Cnrs/Cholla 345kV TTC=1250MW	0 ATC for 742 hrs/yr 62 ATC for 1550 hrs/yr
	PaloVerde-Westwing TTC=1318MW	0 ATC for 318 hrs/yr 66MW ATC for 2294 hrs/yr
	PaloVerde-N.Gila TTC=140MW	0 ATC for 2968 hrs/yr 7 MW ATC for 4294hrs/yr
El Paso	WestMesa-Arroyo 345 TTC=300MW	0 ATC for 7000 hrs/yr
	Sprvl-Luna 345kV Greenlee-Hidalgo 345 TTC=670MW	0 ATC for 7000 hrs/yr
NPC	Red Butte- Harry Allen TTC=300 MW	0 ATC for 3384 hrs/yr
	Harry Allen-Mead TTC=300 MW	0 ATC for 3384 hrs/yr
	Harry Allen-McCull. TTC=300 MW	0 ATC for 3384 hrs/yr
	Navajo-McCull. TTC=360MW	0 ATC for 1248 hrs/yr
PNM	Not Confirmed with PNM: However, Preliminary conclusions are:  SanJuan-4Cnrs to Albuq. voltage limitation for N-1 conditions: 154MW Gas Turbines increase import limitations.	
SRP	Coronado-Kyrene 500kV TTC=1100MW	7MW ATC for all year
	Coronado-PaloVerde TTC=1100MW	7MW ATC for all year
	4Cnrs-Coronado TTC=50MW	0 ATC all year

4Cnrs-4Cnrs TTC=50MW	2MW ATC all year
Mead230-Liberty TTC=160MW	8MW ATC all year
NV-Moen-McCull. TTC=344MW	0 ATC all year
PaloVerde-Coronado TTC=1100MW	13MW ATC Jul-Sep
PaloVerde-Hayden TTC=95MW	13MW ATC Jul-Sep
PaloVerde-PinPeak TTC=554MW	13MW ATC Jul-Aug
SilverKing-Hayden TTC=95MW	21MW ATC May-Aug

TEP           Data not confirmed,  
              Tucson import limit is 950-1000MW  
              Tucson load is 1650MW  
              95% of the year, a local unit is on.  
              81% of the days per year, the load exceeds 950MW

WAPA           Data not confirmed

Re: Must-Run Generation

Company:	Description
=====	=====
AEPC	One of the units at Apache must run all year
APS	Metro-Phx units must-run apx 447 hrs/year when valley load exceeds 5800MW Yuma - Douglas - N-1 contingency
El Paso	Minimum of 3 units must run all year Rio Grand Plant must run to maintain import capability which is 100% of the time in the summer months.
NPC	Data not confirmed
PNM	Data not confirmed
SRP	Metro-Phx units must-run apx 200-400hrs/yr when valley load exceeds 5800MW
WAPA	Data not confirmed

E

Oasis\_~1.txt

Segment	Month	Year	TTC	ATC
Cholla	345-->FC	345, Dec-98	1340	720
Cholla	345-->FC	345, Jan-99	1340	720
Cholla	345-->FC	345, Feb-99	1340	720
Cholla	345-->FC	345, Mar-99	1340	720
Cholla	345-->FC	345, Apr-99	1340	720
Cholla	345-->FC	345, May-99	1340	720
Cholla	345-->FC	345, Jun-99	1340	720
Cholla	345-->FC	345, Jul-99	1340	720
Cholla	345-->FC	345, Aug-99	1340	720
Cholla	345-->FC	345, Sep-99	1340	720
Cholla	345-->FC	345, Oct-99	1340	720
Cholla	345-->Pinn Pk.	345, Dec-98	2133	208
Cholla	345-->Pinn Pk.	345, Jan-99	2133	212
Cholla	345-->Pinn Pk.	345, Feb-99	2133	204
Cholla	345-->Pinn Pk.	345, Mar-99	2133	204
Cholla	345-->Pinn Pk.	345, Apr-99	2133	428
Cholla	345-->Pinn Pk.	345, May-99	2133	804
Cholla	345-->Pinn Pk.	345, Jun-99	2133	12
Cholla	345-->Pinn Pk.	345, Jul-99	2133	1663
Cholla	345-->Pinn Pk.	345, Aug-99	2133	23
Cholla	345-->Pinn Pk.	345, Sep-99	2133	1
Cholla	345-->Pinn Pk.	345, Oct-99	2133	203
FC	230-->FC	345, Dec-98	681	291
FC	230-->FC	345, Jan-99	681	681
FC	230-->FC	345, Feb-99	681	681
FC	230-->FC	345, Mar-99	681	681
FC	230-->FC	345, Apr-99	681	681
FC	230-->FC	345, May-99	681	681
FC	230-->FC	345, Jun-99	681	681
FC	230-->FC	345, Jul-99	681	681
FC	230-->FC	345, Aug-99	681	681
FC	230-->FC	345, Sep-99	681	681
FC	230-->FC	345, Oct-99	681	681
FC	345-->Cholla	345, Dec-98	1340	90
FC	345-->Cholla	345, Jan-99	1340	90
FC	345-->Cholla	345, Feb-99	1340	90
FC	345-->Cholla	345, Mar-99	1340	90
FC	345-->Cholla	345, Apr-99	1340	90
FC	345-->Cholla	345, May-99	1340	90
FC	345-->Cholla	345, Jun-99	1340	90
FC	345-->Cholla	345, Jul-99	1340	90
FC	345-->Cholla	345, Aug-99	1340	90
FC	345-->Cholla	345, Sep-99	1340	90
FC	345-->Cholla	345, Oct-99	1340	90
FC	345-->FC	230, Dec-98	681	681
FC	345-->FC	230, Jan-99	518	518
FC	345-->FC	230, Feb-99	518	518
FC	345-->FC	230, Mar-99	518	518
FC	345-->FC	230, Apr-99	518	518
FC	345-->FC	230, May-99	518	518

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FC 345-->FC 230,Jun-99,518,518  
 FC 345-->FC 230,Jul-99,518,518  
 FC 345-->FC 230,Aug-99,518,518  
 FC 345-->FC 230,Sep-99,518,518  
 FC 345-->FC 230,Oct-99,518,518  
 Gila 69-->N. Gila 500,Dec-98,14,14  
 Gila 69-->N. Gila 500,Jan-99,14,14  
 Gila 69-->N. Gila 500,Feb-99,14,14  
 Gila 69-->N. Gila 500,Mar-99,14,14  
 Gila 69-->N. Gila 500,Apr-99,14,14  
 Gila 69-->N. Gila 500,May-99,14,14  
 Gila 69-->N. Gila 500,Jun-99,14,14  
 Gila 69-->N. Gila 500,Jul-99,14,14  
 Gila 69-->N. Gila 500,Aug-99,14,14  
 Gila 69-->N. Gila 500,Sep-99,14,14  
 Gila 69-->N. Gila 500,Oct-99,14,14  
 Gila 69-->San Luis 34,Dec-98,14,14  
 Gila 69-->San Luis 34,Jan-99,14,14  
 Gila 69-->San Luis 34,Feb-99,14,14  
 Gila 69-->San Luis 34,Mar-99,14,14  
 Gila 69-->San Luis 34,Apr-99,14,14  
 Gila 69-->San Luis 34,May-99,14,14  
 Gila 69-->San Luis 34,Jun-99,14,14  
 Gila 69-->San Luis 34,Jul-99,14,14  
 Gila 69-->San Luis 34,Aug-99,14,14  
 Gila 69-->San Luis 34,Sep-99,14,14  
 Gila 69-->San Luis 34,Oct-99,14,14  
 Mead 230-->Mead 500,Dec-98,236,0  
 Mead 230-->Mead 500,Jan-99,236,0  
 Mead 230-->Mead 500,Feb-99,236,0  
 Mead 230-->Mead 500,Mar-99,236,0  
 Mead 230-->Mead 500,Apr-99,236,0  
 Mead 230-->Mead 500,May-99,236,0  
 Mead 230-->Mead 500,Jun-99,236,0  
 Mead 230-->Mead 500,Jul-99,236,0  
 Mead 230-->Mead 500,Aug-99,236,0  
 Mead 230-->Mead 500,Sep-99,236,0  
 Mead 230-->Mead 500,Oct-99,236,0  
 Mead 500-->Mead 230,Dec-98,236,61  
 Mead 500-->Mead 230,Jan-99,236,86  
 Mead 500-->Mead 230,Feb-99,236,86  
 Mead 500-->Mead 230,Mar-99,236,86  
 Mead 500-->Mead 230,Apr-99,236,86  
 Mead 500-->Mead 230,May-99,236,86  
 Mead 500-->Mead 230,Jun-99,236,86  
 Mead 500-->Mead 230,Jul-99,236,86  
 Mead 500-->Mead 230,Aug-99,236,86  
 Mead 500-->Mead 230,Sep-99,236,86  
 Mead 500-->Mead 230,Oct-99,236,86  
 Mead 500-->Mktplace 500,Dec-98,236,36  
 Mead 500-->Mktplace 500,Jan-99,236,61

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Mead 500-->Mktplace 500, Feb-99, 236, 61  
 Mead 500-->Mktplace 500, Mar-99, 236, 61  
 Mead 500-->Mktplace 500, Apr-99, 236, 61  
 Mead 500-->Mktplace 500, May-99, 236, 86  
 Mead 500-->Mktplace 500, Jun-99, 236, 86  
 Mead 500-->Mktplace 500, Jul-99, 236, 86  
 Mead 500-->Mktplace 500, Aug-99, 236, 86  
 Mead 500-->Mktplace 500, Sep-99, 236, 86  
 Mead 500-->Mktplace 500, Oct-99, 236, 86  
 Mead 500-->Westwing 500, Dec-98, 236, 0  
 Mead 500-->Westwing 500, Jan-99, 236, 0  
 Mead 500-->Westwing 500, Feb-99, 236, 0  
 Mead 500-->Westwing 500, Mar-99, 236, 0  
 Mead 500-->Westwing 500, Apr-99, 236, 0  
 Mead 500-->Westwing 500, May-99, 236, 0  
 Mead 500-->Westwing 500, Jun-99, 236, 0  
 Mead 500-->Westwing 500, Jul-99, 236, 0  
 Mead 500-->Westwing 500, Aug-99, 236, 0  
 Mead 500-->Westwing 500, Sep-99, 236, 0  
 Mead 500-->Westwing 500, Oct-99, 236, 0  
 Mktplace 500-->Mead 500, Dec-98, 236, 236  
 Mktplace 500-->Mead 500, Jan-99, 236, 236  
 Mktplace 500-->Mead 500, Feb-99, 236, 236  
 Mktplace 500-->Mead 500, Mar-99, 236, 236  
 Mktplace 500-->Mead 500, Apr-99, 236, 236  
 Mktplace 500-->Mead 500, May-99, 236, 236  
 Mktplace 500-->Mead 500, Jun-99, 236, 236  
 Mktplace 500-->Mead 500, Jul-99, 236, 236  
 Mktplace 500-->Mead 500, Aug-99, 236, 236  
 Mktplace 500-->Mead 500, Sep-99, 236, 236  
 Mktplace 500-->Mead 500, Oct-99, 236, 236  
 N. Gila 500-->Gila 69, Dec-98, 14, 14  
 N. Gila 500-->Gila 69, Jan-99, 14, 14  
 N. Gila 500-->Gila 69, Feb-99, 14, 14  
 N. Gila 500-->Gila 69, Mar-99, 14, 14  
 N. Gila 500-->Gila 69, Apr-99, 14, 14  
 N. Gila 500-->Gila 69, May-99, 14, 14  
 N. Gila 500-->Gila 69, Jun-99, 14, 14  
 N. Gila 500-->Gila 69, Jul-99, 14, 14  
 N. Gila 500-->Gila 69, Aug-99, 14, 14  
 N. Gila 500-->Gila 69, Sep-99, 14, 14  
 N. Gila 500-->Gila 69, Oct-99, 14, 14  
 N. Gila 500-->P. Verde 500, Dec-98, 140, 140  
 N. Gila 500-->P. Verde 500, Jan-99, 140, 140  
 N. Gila 500-->P. Verde 500, Feb-99, 140, 140  
 N. Gila 500-->P. Verde 500, Mar-99, 140, 140  
 N. Gila 500-->P. Verde 500, Apr-99, 140, 140  
 N. Gila 500-->P. Verde 500, May-99, 140, 140  
 N. Gila 500-->P. Verde 500, Jun-99, 140, 140  
 N. Gila 500-->P. Verde 500, Jul-99, 140, 140  
 N. Gila 500-->P. Verde 500, Aug-99, 140, 140

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N. Gila 500-->P. Verde 500,Sep-99,140,140  
 N. Gila 500-->P. Verde 500,Oct-99,140,140  
 N. Gila 500-->Yucca 69,Dec-98,14,14  
 N. Gila 500-->Yucca 69,Jan-99,14,14  
 N. Gila 500-->Yucca 69,Feb-99,14,14  
 N. Gila 500-->Yucca 69,Mar-99,14,14  
 N. Gila 500-->Yucca 69,Apr-99,14,14  
 N. Gila 500-->Yucca 69,May-99,14,14  
 N. Gila 500-->Yucca 69,Jun-99,14,14  
 N. Gila 500-->Yucca 69,Jul-99,14,14  
 N. Gila 500-->Yucca 69,Aug-99,14,14  
 N. Gila 500-->Yucca 69,Sep-99,14,14  
 N. Gila 500-->Yucca 69,Oct-99,14,14  
 Navajo 500-->Westwing 500,Dec-98,559,134  
 Navajo 500-->Westwing 500,Jan-99,559,244  
 Navajo 500-->Westwing 500,Feb-99,559,244  
 Navajo 500-->Westwing 500,Mar-99,559,244  
 Navajo 500-->Westwing 500,Apr-99,559,244  
 Navajo 500-->Westwing 500,May-99,559,244  
 Navajo 500-->Westwing 500,Jun-99,559,244  
 Navajo 500-->Westwing 500,Jul-99,559,244  
 Navajo 500-->Westwing 500,Aug-99,559,244  
 Navajo 500-->Westwing 500,Sep-99,559,244  
 Navajo 500-->Westwing 500,Oct-99,559,244  
 P. Verde 500-->N. Gila 500,Dec-98,140,0  
 P. Verde 500-->N. Gila 500,Jan-99,140,0  
 P. Verde 500-->N. Gila 500,Feb-99,140,0  
 P. Verde 500-->N. Gila 500,Mar-99,140,0  
 P. Verde 500-->N. Gila 500,Apr-99,140,0  
 P. Verde 500-->N. Gila 500,May-99,140,0  
 P. Verde 500-->N. Gila 500,Jun-99,140,0  
 P. Verde 500-->N. Gila 500,Jul-99,140,0  
 P. Verde 500-->N. Gila 500,Aug-99,140,0  
 P. Verde 500-->N. Gila 500,Sep-99,140,0  
 P. Verde 500-->N. Gila 500,Oct-99,140,0  
 P. Verde 500-->Westwing 500,Dec-98,1318,0  
 P. Verde 500-->Westwing 500,Jan-99,1318,0  
 P. Verde 500-->Westwing 500,Feb-99,1318,0  
 P. Verde 500-->Westwing 500,Mar-99,1318,0  
 P. Verde 500-->Westwing 500,Apr-99,1318,0  
 P. Verde 500-->Westwing 500,May-99,1318,0  
 P. Verde 500-->Westwing 500,Jun-99,1318,0  
 P. Verde 500-->Westwing 500,Jul-99,1318,0  
 P. Verde 500-->Westwing 500,Aug-99,1318,0  
 P. Verde 500-->Westwing 500,Sep-99,1318,0  
 P. Verde 500-->Westwing 500,Oct-99,1318,0  
 Pinn Pk. 345-->Cholla 345,Dec-98,2133,1543  
 Pinn Pk. 345-->Cholla 345,Jan-99,2133,1653  
 Pinn Pk. 345-->Cholla 345,Feb-99,2133,1653  
 Pinn Pk. 345-->Cholla 345,Mar-99,2133,1653  
 Pinn Pk. 345-->Cholla 345,Apr-99,2133,1653

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Pinn Pk. 345-->Cholla 345,May-99,2133,1653  
 Pinn Pk. 345-->Cholla 345,Jun-99,2133,1653  
 Pinn Pk. 345-->Cholla 345,Jul-99,2133,1653  
 Pinn Pk. 345-->Cholla 345,Aug-99,2133,1653  
 Pinn Pk. 345-->Cholla 345,Sep-99,2133,1653  
 Pinn Pk. 345-->Cholla 345,Oct-99,2133,1653  
 San Luis 34-->Gila 69,Dec-98,14,14  
 San Luis 34-->Gila 69,Jan-99,14,14  
 San Luis 34-->Gila 69,Feb-99,14,14  
 San Luis 34-->Gila 69,Mar-99,14,14  
 San Luis 34-->Gila 69,Apr-99,14,14  
 San Luis 34-->Gila 69,May-99,14,14  
 San Luis 34-->Gila 69,Jun-99,14,14  
 San Luis 34-->Gila 69,Jul-99,14,14  
 San Luis 34-->Gila 69,Aug-99,14,14  
 San Luis 34-->Gila 69,Sep-99,14,14  
 San Luis 34-->Gila 69,Oct-99,14,14  
 San Luis 34-->Yucca 69,Dec-98,14,14  
 San Luis 34-->Yucca 69,Jan-99,14,14  
 San Luis 34-->Yucca 69,Feb-99,14,14  
 San Luis 34-->Yucca 69,Mar-99,14,14  
 San Luis 34-->Yucca 69,Apr-99,14,14  
 San Luis 34-->Yucca 69,May-99,14,14  
 San Luis 34-->Yucca 69,Jun-99,14,14  
 San Luis 34-->Yucca 69,Jul-99,14,14  
 San Luis 34-->Yucca 69,Aug-99,14,14  
 San Luis 34-->Yucca 69,Sep-99,14,14  
 San Luis 34-->Yucca 69,Oct-99,14,14  
 Westwing 500-->Mead 500,Dec-98,236,36  
 Westwing 500-->Mead 500,Jan-99,236,61  
 Westwing 500-->Mead 500,Feb-99,236,61  
 Westwing 500-->Mead 500,Mar-99,236,61  
 Westwing 500-->Mead 500,Apr-99,236,61  
 Westwing 500-->Mead 500,May-99,236,86  
 Westwing 500-->Mead 500,Jun-99,236,86  
 Westwing 500-->Mead 500,Jul-99,236,86  
 Westwing 500-->Mead 500,Aug-99,236,86  
 Westwing 500-->Mead 500,Sep-99,236,86  
 Westwing 500-->Mead 500,Oct-99,236,86  
 Westwing 500-->Navajo 500,Dec-98,559,449  
 Westwing 500-->Navajo 500,Jan-99,559,559  
 Westwing 500-->Navajo 500,Feb-99,559,559  
 Westwing 500-->Navajo 500,Mar-99,559,559  
 Westwing 500-->Navajo 500,Apr-99,559,559  
 Westwing 500-->Navajo 500,May-99,559,559  
 Westwing 500-->Navajo 500,Jun-99,559,559  
 Westwing 500-->Navajo 500,Jul-99,559,559  
 Westwing 500-->Navajo 500,Aug-99,559,559  
 Westwing 500-->Navajo 500,Sep-99,559,559  
 Westwing 500-->Navajo 500,Oct-99,559,559  
 Westwing 500-->P. Verde 500,Dec-98,1318,968

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Westwing 500-->P. Verde 500,Jan-99,1318,968  
 Westwing 500-->P. Verde 500,Feb-99,1318,968  
 Westwing 500-->P. Verde 500,Mar-99,1318,968  
 Westwing 500-->P. Verde 500,Apr-99,1318,968  
 Westwing 500-->P. Verde 500,May-99,1318,968  
 Westwing 500-->P. Verde 500,Jun-99,1318,968  
 Westwing 500-->P. Verde 500,Jul-99,1318,968  
 Westwing 500-->P. Verde 500,Aug-99,1318,968  
 Westwing 500-->P. Verde 500,Sep-99,1318,968  
 Westwing 500-->P. Verde 500,Oct-99,1318,968  
 Yucca 69-->N. Gila 500,Dec-98,14,14  
 Yucca 69-->N. Gila 500,Jan-99,14,14  
 Yucca 69-->N. Gila 500,Feb-99,14,14  
 Yucca 69-->N. Gila 500,Mar-99,14,14  
 Yucca 69-->N. Gila 500,Apr-99,14,14  
 Yucca 69-->N. Gila 500,May-99,14,14  
 Yucca 69-->N. Gila 500,Jun-99,14,14  
 Yucca 69-->N. Gila 500,Jul-99,14,14  
 Yucca 69-->N. Gila 500,Aug-99,14,14  
 Yucca 69-->N. Gila 500,Sep-99,14,14  
 Yucca 69-->N. Gila 500,Oct-99,14,14  
 Yucca 69-->San Luis 34,Dec-98,14,14  
 Yucca 69-->San Luis 34,Jan-99,14,14  
 Yucca 69-->San Luis 34,Feb-99,14,14  
 Yucca 69-->San Luis 34,Mar-99,14,14  
 Yucca 69-->San Luis 34,Apr-99,14,14  
 Yucca 69-->San Luis 34,May-99,14,14  
 Yucca 69-->San Luis 34,Jun-99,14,14  
 Yucca 69-->San Luis 34,Jul-99,14,14  
 Yucca 69-->San Luis 34,Aug-99,14,14  
 Yucca 69-->San Luis 34,Sep-99,14,14  
 Yucca 69-->San Luis 34,Oct-99,14,14

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**WESTERN INTERCONNECTION**  
**BIENNIAL TRANSMISSION PLAN**

**May, 1998**

**Northwest Regional Transmission Association  
Southwest Regional Transmission Association  
Western Regional Transmission Association**

This report was prepared in cooperation with the Western Systems Coordinating Council, the Committee on Regional Electric Power Cooperation and the Colorado Coordinated Planning Group

## **B. WESTERN INTERCONNECTION COMMERCIAL USES**

This section of the Plan presents an assessment of the commercial uses of the Western Interconnected transmission system. Information is presented based on User's experience obtaining access to the system for commercial purposes during 1997. This information was obtained from a survey of Transmission Users' experience with posted Available Transfer Capability (ATC) and from information available on the OASIS sites in the Western Interconnection. This Plan is the first attempt to assemble information on the ability of the Western Interconnection to meet Users' commercial needs. While problems in the Western Interconnection appear to be less than the other parts of the country, a number of concerns were identified in the above survey as described herein. These are discussed further in Section V. The effort was limited in this initial Plan to an assessment of the major transmission paths in the Western Interconnection. In future Plans, as information on path loadings and information on OASIS transmission service requests becomes more readily available, analysis can be extended to include additional paths in the Western Interconnection.

The following information is presented in this section:

**Section 1.** – Results of a survey of Transmission Users regarding their experience with congested paths in the Western Interconnection during 1997

**Section 2.** – Results of a WSCC Production / Costing study analyzing the cost impact of transmission bottlenecks in the Western Interconnection

**Section 3.** – An assessment of the existing loadings on the major transmission paths in the Western Interconnection, utilizing weekly peak and light load information and available hourly loading information. The percentage of time that a path exceeds 75% and 90% of its rating is shown. Most of the percentage information is associated with the paths' Rated Transfer Capability (RTC). Information was available and is presented for the Pacific AC Intertie relating this percentage to the hourly Operating Transfer Capability (OTC).

**Section 4.** – An assessment of OASIS posted Refused Transmission Service Requests for the months of January and August, 1997, based upon audit log information from the Western Interconnection OASIS sites.

**Section 5.** – A tabulation of the transmission paths in the Western Interconnection that have had ATC posted as zero on the OASIS sites during January or August 1997.

### **1. Transmission Congestion Survey**

WICF's ATC Task Force conducted an ATC survey of Transmission Users within the Western Interconnection in November 1997. Responses were received from 31 entities. NERC and SWRTA are also conducting ATC related surveys. In WICF's survey Users were asked to indicate what their experience has been regarding obtaining or being denied transmission access as a result of congested transmission paths in the Western Interconnection. Specifically they were asked to answer the following question:

**"As a transmission Customer, are there paths over which you have requested and been refused access because of unavailable capacity? Are there paths over which you have desired but not requested capacity because the posted ATC was zero? (Please indicate the path name(s) and the extent of the problem. If unavailable capacity has not been a problem, please so indicate)."**

The survey requested information on the extent of the problem, however no information of this type was provided. It can be concluded from the survey that congestion as measured by unavailable ATC is occurring in the Western Interconnection. However from this survey, conclusions cannot be drawn regarding the severity of the congestion or the amount of energy not being transacted as a result of the lack of available capacity or lack of information on parallel paths. The ATC Task Force will address further analysis of these congestion issues in the future.

The following Paths were identified in this survey as those Paths over which Customers have either been denied access or over which they have desired but not requested access because the ATC was posted as zero:

**Pacific Northwest/Canada**

- BC Hydro to BPA
- BC Hydro to Alberta
- John Day to COB
- LaGrande - Brownlee - Boise (BPA to Idaho)
- Big Eddy to NOB
- Montana to BPA

**California/Southern Nevada and into Arizona**

- COB to Midway or Sylmar
- Palo Verde to Sylmar
- NOB to Sylmar
- PG&E to SCE (Path 15)
- COB to Palo Verde
- NOB to Palo Verde
- COB to MD (Mead)
- NOB to MD (Mead)
- Midway to MD (Mead)
- Midway to Palo Verde
- Drum to PG&E 115 kV
- Cascade to PG&E 115 kV

**Arizona/New Mexico**

- Four Corners to Pinnacle Peak
- Four Corners to Glenn Canyon
- Palo Verde to Westwing
- Four Corners to Mexico (through El Paso)
- WSCC to Southwest Power Pool (dc tie)
- Four Corners/San Juan to Blackwater dc tie

**Utah/Colorado/Wyoming**  
Borah to Glen Canyon  
Yellowtail to WW  
Yellowtail to Navajo  
WSCC to MAPP (dc tie)

One Transmission User indicated in response to the survey that there is very little Monthly Firm ATC available in the Western Interconnection. That User indicated that "the only paths that are somewhat available are Mead to Westwing (ATC in February to May and October to December), Sylmar to Palo Verde (ATC available January through November), COB to Mead (January, March, April, September to November), COB to Palo Verde (January, March, April, September to November), Midway to Mead (January, March April, September to November). All of the others are zero."

## **2. WSCC 1996 Transmission Bottleneck Study**

WSCC conducted a transmission bottleneck study of the Western Interconnection transmission system in 2004 and issued the report "WSCC Transmission Bottleneck Study Report" dated January 1997. There are currently no plans to update the 1996 study. These studies investigate the effect of various assumptions and conditions on the cost of energy production. Results of these studies are valid only for the assumptions studied. In addition, the analysis tools are still under development. For example, improved hydro models are needed for Western Interconnection studies because of the large hydro resource base.

Among the sensitivities that were investigated were changes in hydro conditions (high, median and critical), changes in gas prices, changes in load growth rates, removal of transmission congestion, inclusion or deletion of various future planned projects.

Generation was added in accordance with projected resource plans. In addition to planned generation, unplanned resources were added in southern Nevada and Alberta to keep from overloading transmission under normal conditions.

Sensitivity studies were conducted with and without planned transmission projects in Phases 1 and 2 of the "Project Review and Rating Procedure" to evaluate the associated potential production cost savings. Therefore, the following major projects were not included in the study:

Southwest Intertie Project  
Navajo Transmission Project

Given these assumptions, the study concluded that the following paths are the five most congested transmission areas in the Western Interconnection. This does not mean that it is economical to build new transmission facilities to remove the congestion. In some cases, projects have been considered in the past or are being currently studied. Additional feasibility and cost/benefit analysis by project sponsors will be needed.

Transmission into Alberta  
Transmission into southern Nevada  
Transmission from Colorado

Transmission into northern Nevada  
Transmission from Idaho and Montana

The Bottleneck studies were performed prior to the outages during the summer of 1996. Therefore the California – Oregon Intertie (COI) was not represented as having a reduced OTC and study results did not identify the current congestion on the COI.

### 3. Existing System Loadings on the Main Grid System

An analysis of path loadings on the major control area interconnections, both actual and scheduled, gives an indication of the commercial use being made on today's system. This can be an indicator of where commercial demand on the system is high and where there may be a need to consider expansion of the system to meet future commercial needs.

As addressed by the reliability studies in Section A.1 and A.2 of this Section III, path loadings may also be indicative of potential reliability risk. Generally, the more often a path is loaded at high levels the greater the exposure to the effects of system outages or other emergency conditions.

Most of the path loading and schedule information presented in this Section of the Plan was obtained from the WSCC Weekly Interchange Diagrams. Hourly path loading information is not readily available and therefore very little of this information is presented. The Weekly Interchange Diagrams provide both actual and scheduled path loadings recorded on a once a week basis for a peak load hour and a light load hour. This information is not available after June 1996. It is recognized that weekly path loading data is not a good sample for statistical analysis, however it does give an indication of how the paths are being used, though most severe loading information is not obtained. Table III lists the Paths analyzed in this section of the Plan and the lines within those paths. Figure 6 shows the location of the Paths within the WSCC system.

Except for the Pacific AC Intertie, the loading analysis included in this Plan utilizes the Rated Transfer Capability (RTC) of the paths for calculation of percentage use or utilization. This was done because Operating Transfer Capability (OTC) information, the actual capability of a path at a specific operating time, was generally not available. Use of RTC understates the percentage usage relative to the actual capability. Utilization measured against OTC is a preferred indicator.

It should be noted that the path ratings shown in the following tables and throughout this report do not provide the formally adopted path ratings by the owners/participants of the transmission paths. New and revised transmission path ratings need to be reviewed and agreed upon by the transmission path owners and market participants. Final path ratings shall be granted through the WSCC path rating process.

Because of recent interest in the Pacific AC Intertie, the Bonneville Power Administration has performed considerable statistical analysis of the Intertie loadings. This information is available on the BPA Web Site (<http://www.bpa.gov>). Using BPA's work, information on Pacific AC Intertie loadings relative to the Operating Transfer Capability (OTC) is presented. This information may also be available from other Transmission Providers, however it has not been readily obtainable and is therefore not included in this report. It may be beneficial for future reports to include this type of assessment for other major

paths in the Western Interconnection. Table VI presents information on the Pacific AC Intertie utilization relative to OTC.

The following Tables summarize the results of the path loading assessment:

**Table IV**

This table presents the actual and scheduled loadings on the major Western Interconnection paths for 1995 and 1996 (through June). Average and maximum loadings, both peak load and light load, are presented. Information is presented by both MW and % of RTC.

**Table V**

This table presents the percentage of time the actual and scheduled loadings exceed 75% and 90% of path rating or RTC. This gives an indication of how frequently the major paths are operated near their full capacity. Where hourly information was available, this information is presented on an annual basis. The table notes whether the information is derived from Hourly or Weekly data. Information is presented in the table for the Pacific AC Intertie relative to OTC, using hourly data.

**Table VI**

This table presents, for the Pacific AC Intertie, the utilization compared to OTC for 1995 and 1996 by month. Maximum and average loadings by month are also presented.

# TABLE III

## TRANSFER PATH DESCRIPTION

<u>PATH NAME</u>	<u>FACILITIES</u>
1. Arizona - New Mexico	Four Corners - San Juan 345 kV Four Corners - West Mesa 345 kV Four Corners - Gallegos - Ambrosia 230 kV McKinley - San Juan 345 kV McKinley - Yah Ta Hey 115 kV Greenlee - Hidalgo 345 kV Springerville - Luna 345 kV
2. California - Oregon Intertie	Malin - Round Mtn. #1 and #2 500 kV lines Captain Jack - Olinda 500 kV
3. East of the Colorado River	Navajo - McCullough 500 kV Moenkopi - Eldorado 500 kV Palo Verde - Devers 500 kV Palo Verde - North Gila 500 kV Liberty - Mead 345 kV Perkins - Mead 500 kV
4. Four Corners Area	Four Corners - Moenkopi 500 kV Four Corners - Cholla #1 & #2 345 kV
5. Idaho Area - Borah West	Kinport - Midpoint 345 kV Borah - Adelaide - Midpoint #1 & #2 345 kV AmFalls - Pleasant Valley - Adelaide 138 kV AmFalls - Raft River - Minidoka 138 kV
6. Idaho Area - Brownlee East	Brownlee - Boise #1, #2, #3 230 kV Brownlee - Ontario - Boise 230 kV Oxbow - McCall 138 kV Quartz - Ontario 138 kV Quartz - Weiser - Ontario 69 kV
7. Idaho to Northwest	Midpoint - Summer Lake 500 kV Oxbow - Lolo 230 kV Hells Canyon - Enterprise 230 kV Quartz Tap - La Grande 230 kV Hines - Harney 138/115 kV tie
8. Idaho - Sierra	Midpoint - Valmy 345 kV
9. IPP DC Line	Intermountain Power Project +/- 500 kV DC line
10. Midway - Vincent	Midway - Vincent #1, #2, & #3 500 kV lines

<b>11. Midpoint – Summer Lake</b>	Midpoint – Summer Lake 500 kV
<b>12. Montana to Northwest</b>	Broadview - Garrison #1 & #2 500 kV Anaconda - Garrison #1 & #2 230 kV Ovando - Garrison 230 kV Ovando - Hot Springs 230 kV Garrison - Rattlesnake 230 kV Rattlesnake - Hot Springs 230 kV Kerr - Elmo 115 kV Thompson Falls - Burke 115 kV Crow Creek - Burke 115 kV
<b>13. Northwest – Canada</b>	Custer – Ingledow 500 kV #1 and #2 Boundary – Waneta 230 kV Boundary – Nelway 230 kV
<b>14. Pacific DC Intertie</b>	Pacific DC Intertie - +/- 500 kV
<b>15. South of SONGS</b>	San Onofre 230 kV bus looking south into SDG&E system
<b>16. TOT 1A</b>	Bears Ears - Bonanza 345 kV Hayden - Artesia 138 kV Meeker - Southwest Rangely 138 kV
<b>17. TOT 2A</b>	Lost Canyon - Shiprock 230 kV Durango - Shiprock 115 kV Waterflow - San Juan 345 kV
<b>18. TOT 2B</b>	Sigurd - Glenn Canyon 230 kV Pinto - Four Corners 345 kV
<b>19. TOT 2C</b>	Red Butte - Harry Allen 345 kV
<b>20. TOT 4A</b>	Dave Johnston - Difficulty 230 kV Riverton - Wyopo 230 kV Spence - Mustang 230 kV
<b>21. TransAlta – BC Hydro</b>	Langdon – Cranbrook 500 kV Pocatera – Fording Coal Tap 138 kV Colman – Natal 138 kV

FIGURE 6.

WSCC TRANSMISSION PATHS

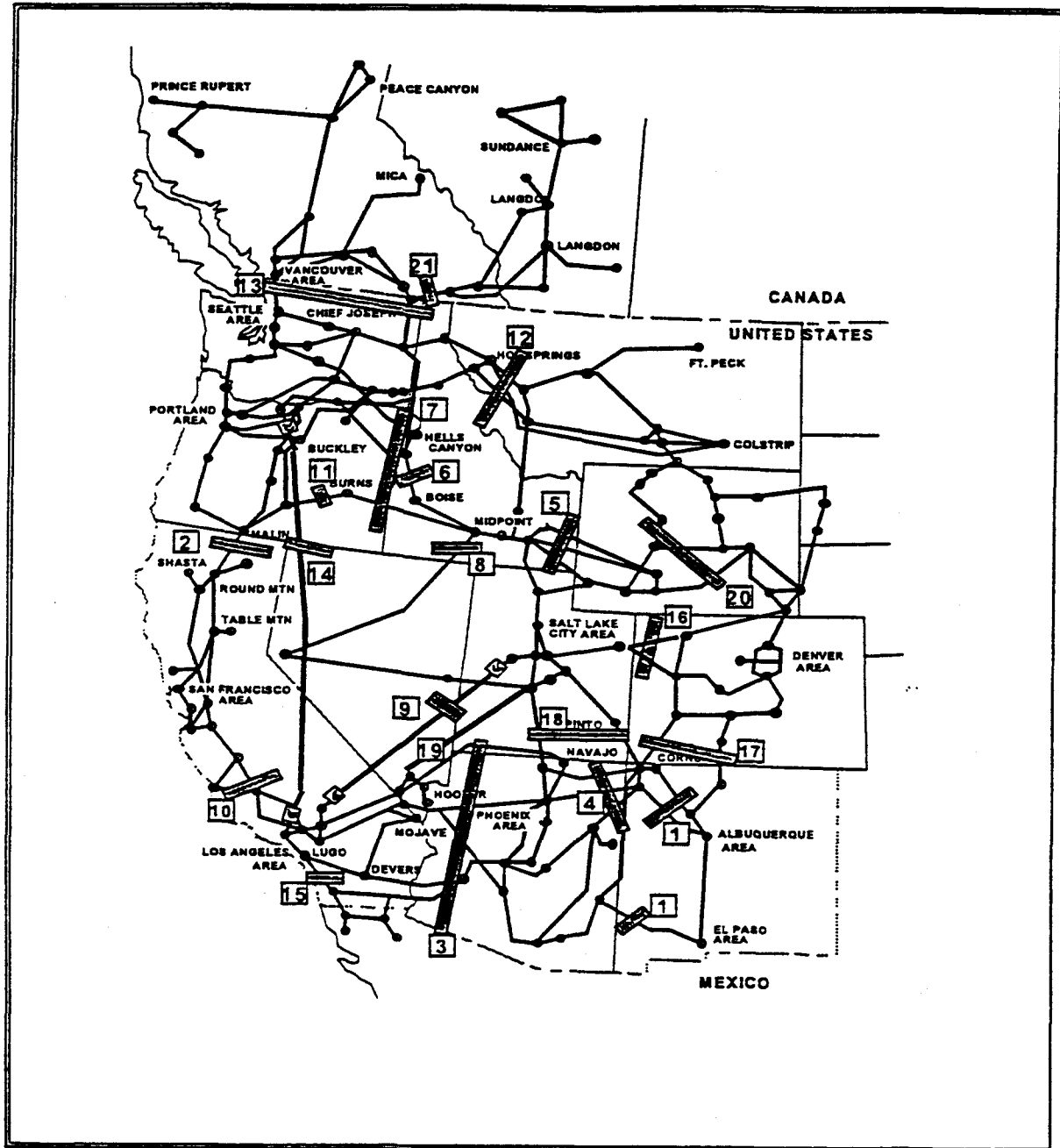


TABLE IV

**PATH LOADINGS FOR MAJOR WESTERN INTERCONNECTION PATHS**  
**WSCC Weekly Interchange Diagram Summary**  
**January 1995 through June 1996 (see note 3)**  
**Actual Flow and Schedule Flow - Peak and Light Load Hours**

PATH	RATING (WSCC Accepted Rating in bold)	PEAK LOAD HOURS				LIGHT LOAD HOURS			
		Actual Mean (% of Rating)	Actual Max. (% of Rating)	Schedule Mean (% of Rating)	Schedule Max. (% of Rating)	Actual Mean (% of Rating)	Actual Max. (% of Rating)	Schedule Mean (% of Rating)	Schedule Max. (% of Rating)
East of Colorado River (See Note 4)	7550 (1996 rating)	2827 (37%)	4829 (64%)	N.A.	N.A.	2370 (31%)	4512 (60%)	N.A.	N.A.
NE/SE Boundary (2A + 2B + 2C) (See Note 1)	2A - 690 2B - 820 2C - 300	674	1242	N.A.	N.A.	499	997	N.A.	N.A.
TOT 1A (Colorado to Utah)	650	232 (36%)	509 (78%)	N.A.	N.A.	199 (31%)	389 (60%)	N.A.	N.A.
TOT 2A (Colorado to New Mexico)	690	203 (29%)	437 (63%)	170 (25%)	448 (65%)	145 (21%)	398 (58%)	124 (18%)	362 (52%)
TOT 2B (Utah to Arizona/New Mexico)	820	174 (21%)	449 (55%)	242 (30%)	559 (68%)	132 (16%)	579 (71%)	182 (22%)	546 (67%)
TOT 2C (Utah to Nevada)	300	168 (56%)	307 (102%)	180 (60%)	300 (100%)	147 (50%)	292 (97%)	126 (42%)	300 (100%)
TOT 4A (Wyoming)	810	235 (29%)	490 (60%)	N.A.	N.A.	246 (30%)	509 (63%)	N.A.	N.A.
Four Corners Area	2300	1400 (61%)	1959 (85%)	N.A.	N.A.	1061 (46%)	1971 (86%)	N.A.	N.A.
Midway - Vincent	3000	1152 (38%)	2543 (85%)	1203 (40%)	N-S 2525	922 (Note 2)	N-S 2879 S-N 2095	922 **	N-S 1694 S-N 2310
California - Oregon Inter tie	4800	1978 (41%)	4270 (89%)	1998 (42%)	N-S 4136	1036 (Note 2)	2926 (61%)	925 **	N-S 2806 S-N 1755
Pacific DC Inter tie	3100	1150 (37%)	2789 (90%)	1150 (37%)	N-S 2811	778 (Note 2)	2904 (95%)	778 **	N-S 2904 S-N 1291

**TABLE IV (Continued)**

PATH	RATING	PEAK LOAD HOURS				LIGHT LOAD HOURS			
		Actual Mean (% of Rating)	Actual Max. (% of Rating)	Schedule Mean (% of Rating)	Schedule Max. (% of Rating)	Actual Mean (% of Rating)	Actual Max. (% of Rating)	Schedule Mean (% of Rating)	Schedule Max. (% of Rating)
Idaho to Northwest	2400	540 **	1256 (52%)	546 **	1308 (54%)	836 (35%)	1637 (68%)	987 (41%)	1739 (72%)
Montana to Northwest	2200	776 (35%)	1678 (76%)	871 (40%)	1992 (91%)	1000 (45%)	2130 (97%)	1015 (46%)	2190 (100%)
IPP DC Line	1920	1445 (75%)	1917 (100%)	1445 (75%)	1917 (100%)	864 (45%)	1717 (89%)	864 (45%)	1778 (93%)

**Note 1** - Combined rating of 2A, 2B, and 2C has not been determined, therefore percentage of rating is not calculated

**Note 2** - Mean flow represents the mean of flows in both directions. Since the ratings are different in both directions, a "percentage of rating" was not calculated.

**Note 3** - The WSCC Hourly Interchange Data from which this table was developed ceased to be available after June, 1996 and is not available today.

**Note 4** - East of Colorado River statistics are calculated using the 1996 rating of 7550 MW.

N.A. = Not Available

TABLE V

**PERCENTAGE OF TIME PATH LOADINGS  
EXCEED 75% and 90% of PATH RATING**

Path Name	Path Rating (RTC) (See Note 6 re. WSCC ratings)	Hourly or Weekly Data	% of Path Rating	Actual or Scheduled	Peak L 1995	Light L 1995	Peak L 1996	Light L 1996
Arizona to New Mexico	2000 MW E to W (See Note 4)	W	75%	Actual	0	0	0	0
		W	90%	Actual	0	0	0	0
		W	75%	Scheduled	0	0	0	0
		W	90%	Scheduled	0	0	0	0
California - Oregon Inter tie	Using OTC (variable) Using OTC (variable) 4800 MW N to S 4800 MW N to S	H	75%	Actual	6%	6%	37%	
		H	90%	Actual	1%	1%	18%	
		W	75%	Scheduled	2%	0	16%	0
		W	90%	Scheduled	0	0	0	0
East of Colorado River (See Note 1 below)	5700 MW - 1995 7550 MW - 1996 (Accepted Rating)	H	75%	Actual	8%	8%	0%	
		H	90%	Actual	0%	0%	0%	
		H	75%	Scheduled	5%	5%	0%	
		H	90%	Scheduled	0%	0%	0%	
Four Corners Area	2300 MW	W	75%	Actual	12%	12%	12%	0
		W	90%	Actual	0	0	0	0
		W	75%	Scheduled	*	*	*	*
		W	90%	Scheduled	*	*	*	*
Idaho Area - Borah West	2307 MW E to W	H	75%	Actual	9%	9%	7%	(4% in '97)
		H	90%	Actual	1%	1%	<1%	(0% in '97)
		H	75%	Scheduled	17%	17%	12%	(5% in '97)
		H	90%	Scheduled	3%	3%	4%	(<1% in '97)
		H	90%	Scheduled	1%	1%	5%	(3% in '97)

TABLE V (Continued)

Path Name	Path Rating (RTC)	Hourly or Weekly Data	% of Path Rating	Actual or Scheduled	Peak L 1995	Light L 1995	Peak L 1996	Light L 1996
Idaho Area - Brownlee East	2100 MW W to E	H	75%	Actual		8 %	6%	(4% in '97)
		H	90%	Actual		0	<1%	(0% in '97)
		H	75%	Scheduled		10 %	13%	(14% in '97)
Idaho - Northwest East to West	2400 MW E to W	H	75%	Actual		1		
		H	90%	Actual		0	1%	(2% in '97)
		H	75%	Scheduled		0	0	(0% in '97)
		H	90%	Scheduled		<1%	4%	(5% in '97)
Idaho - Northwest West to East	1200 MW W to E	H	75%	Actual		0	0	(0% in '97)
		H	90%	Actual		0	0	(0% in '97)
		H	75%	Scheduled		0	1%	(0% in '97)
		H	90%	Scheduled		0	0	(0% in '97)
Idaho to Sierra	500 MW E to W	W	75%	Actual	0	0	0	0
		W	90%	Actual	0	0	0	0
		W	75%	Scheduled	2	6	16	32
		W	90%	Scheduled	0	2	4	12
IPP DC Line	1920 MW E to W	W	75%	Actual	73%	15%	35%	0
		W	90%	Actual	38%	0	15%	0
		W	75%	Scheduled	73%	15%	35%	0
		W	90%	Scheduled	38%	38%	15%	0
Midway - Vincent	3000 MW N to S	W	75%	Actual	4%	0%	13%	0
		W	90%	Actual	0	0	0	0
		W	75%	Scheduled	2%	0%	4%	0
		W	90%	Scheduled	0	0	0	0

**TABLE V (Continued)**

Path Name	Path Rating (RTC)	Hourly or Weekly Data	% of Path Rating	Actual or Scheduled	Peak L 1995	Light L 1995	Peak L 1996	Light L 1996
Midpoint - Summer Lake	1500 MW E to W							
		W	75%	Actual	0	6	0	0
		W	90%	Actual	0	0	0	0
		W	75%	Scheduled	*	*	*	*
Montana - Northwest	2200 MW E to W (Accepted Rating)	W	90%	Scheduled	*	*	*	*
		H	75%	Actual	19%		12%	
		H	90%	Actual	2%		2%	
Northwest - Canada	2300 MW N to S	W	75%	Scheduled	8%	51%	0	0
		W	90%	Scheduled	2%	22%	0	0
		W	75%	Actual	0	0	0	0
Northwest - Canada	2000 MW S to N	W	90%	Actual	0	0	0	0
		W	75%	Actual	0	0	0	0
		W	75%	Scheduled	*	*	*	*
		W	90%	Scheduled	*	*	*	*
Pacific DC Intertie	3100 MW N to S							
		W	75%	Actual	8%	0	0	18%
		W	90%	Actual	4%	0	0	5%
		W	75%	Scheduled	*	*	*	*
South of San Onofre (SONGS)	1200 MW (See Note 5)	W	90%	Scheduled	*	*	*	*
		H	75%	Actual	1%		16%	
		H	90%	Actual	<1%		4%	
South of San Onofre (SONGS)	1200 MW (See Note 5)	W	75%	Scheduled	0	2%	12%	4%
		W	90%	Scheduled	0	0	4%	4%
		W	75%	Actual	0	8%	0	0
South of San Onofre (SONGS)	1200 MW (See Note 5)	W	90%	Actual	0	8%	0	0
		W	75%	Scheduled	0	71%	0	0
		W	90%	Scheduled	0	71%	0	0

TABLE V (Continued)

Path Name	Path Rating (RTC)	Hourly or Weekly Data	% of Path Rating	Actual or Scheduled	Peak L 1995	Light L 1995	Peak L 1996	Light L 1996
TOT 1A (Colorado - Utah)	650 MW	W	75%	Actual	2%	0	0	0
		W	90%	Actual	0	0	0	0
		W	75%	Scheduled	*	*	*	*
		W	90%	Scheduled	*	*	*	*
TOT 2A (Colorado - NM)	690 MW N to S	W	75%	Actual	0	0	0	0
		W	90%	Actual	0	0	0	0
		W	75%	Scheduled	0	0	0	0
		W	90%	Scheduled	0	0	0	0
TOT 2B (Utah - Arizona/NM)	820 MW N to S	W	75%	Actual	0	0	0	0
		W	90%	Actual	0	0	0	0
		W	75%	Scheduled	0	0	0	0
		W	90%	Scheduled	0	0	0	0
TOT 2C (Utah - Nevada)	300 MW E to W	W	75%	Actual	17%	16%	13%	12%
		W	90%	Actual	2%	0	4%	4%
		W	75%	Scheduled	34%	4%	52%	25%
		W	90%	Scheduled	19%	0	44%	25%
TOT 4A (Wyoming)	810 MW	W	75%	Actual	0	0	0	0
		W	90%	Actual	0	0	0	0
		W	75%	Scheduled	*	*	*	*
		W	90%	Scheduled	*	*	*	*
TransAlta - BC Hydro	1000 MW E to W	W	75%	Actual	0	13%	0	0
		W	90%	Actual	0	0	0	0
		W	75%	Scheduled	*	*	*	*
		W	90%	Scheduled	*	*	*	*

- **Note 1** - Prior to uprating to 7550 MW in 1996, EOR had these loading statistics: In 1994 - actual exceeded 75% of rating 22 % of time and 90 %, 2 % of time; scheduled interchange exceeded 75% of rating 15% of time and 90%, 1 % of time
- **Note 2** - Information in this table comes from (1) WSCC Weekly Interchange Diagrams, noted as weekly (W) or (2) hourly SCADA data on the paths for which this was available, noted as hourly (H). Where hourly data is noted, the analysis is over the entire year rather than separated into peak and light load hours. Limited 1997 information was available and is noted where reported.
- **Note 3** - Information not available denoted by (\*)
- **Note 4** - The Arizona - New Mexico path is a combination of the Southern New Mexico (NMI) path which has a WSCC Accepted Rating of 1048 MW and the Northern New Mexico (NM2) path which has a WSCC rating of 1450 MW. The combined path does not have a WSCC Accepted Rating.
- **Note 5** - South of SONGS rating was 1200 MW in 1995-96. There is now a WSCC Accepted Rating of 1800 MW in the North to South direction.
- **Note 6** - All ratings are "Existing Ratings" as noted in the WSCC 1997 Path Rating Catalog except where WSCC "Accepted Ratings" are noted in bold.

**TABLE VI****PACIFIC AC INTERTIE UTILIZATION****1995 and 1996****Measured relative to Operating Transfer Capability (OTC)**

Month	Average Capacity Available N to S - (%)	Average Loading (MW)	Maximum Loading (MW)	Average Utilization relative to OTC (%)
January, 1995	96.3	-30	1262	12.6
February	94.5	-8	2031	14.9
March	97.6	-27	2397	17.2
April	90.1	-470	1710	22.9
May	93.8	389	2812	22.4
June	97.0	1521	4279	35.5
July	98.9	1504	4190	34.0
August	99.6	980	3602	23.9
September	96.7	660	3231	22.3
October	91.5	1314	3400	35.9
November	96.5	1943	4080	46.4
December	80.5	2336	4019	70.2
January, 1996	57.5	2196	2998	80.1
February	95.5	1675	3482	36.9
March	85.2	1577	3422	39.3
April	92.4	2469	4593	56.6
May	97.4	2490	4514	53.2
June	93.4	3187	4861	71.4
July	86.9	3218	4775	77.4
August (Note)	72.8	2948	4478	84.9
September	66.1	2317	3262	73.3
October	65.4	2115	3247	67.9
November	66.5	1516	3130	47.6
December	66.6	1030	2744	39.0

**Note:** Intertie OTC was limited to 3200 MW during the months of August through December, 1996, following the August 10, 1996, system disturbance. Previous to this, the OTC was generally 4800 MW.

**Average Capacity Available** – actual capacity (OTC) / rated capacity (RTC), averaged for each hour over the month

**Average Loading** – hourly actual loadings averaged algebraically over the month, pos = N to S, neg = S to N

**Maximum Loading** – hourly maximum loading over the month

**Average Utilization relative to OTC** – actual loading / actual capacity (OTC), averaged for each hour over the month, includes both N to S and S to N flows and includes loop flow in actual flow numbers

#### 4. Assessment of Denied Schedule Requests

In order to assess the ability of the Western Interconnection transmission system to meet the commercial needs for transmission availability for buying and selling energy, information on Refused requests has been gathered from the OASIS sites. This information might indicate the existence of a congested path. This information by itself does not give a complete indication of the existence of congested paths. For example, paths with posted ATC = 0 may not receive schedule requests because the paths are posted as not being available for other business. This does not mean there isn't potential business that could use the path if capacity were available.

OASIS posted Refusal actions are identified in Table VIII for the months of January and August 1997. Not all Refusals are due to lack of ATC; many are due to lack of agreement on price. When Refusals due to lack of ATC could be determined, the information is presented. Only those Refusals due to lack of ATC are significant to the identification of transmission congestion.

Refused requests for all types of service are combined into a single number, that is, hourly, daily, monthly and firm/non-firm are not identified separately. Refusals of over 50 MW capacity are identified separately, to give some indication of the number of Refusals of larger capacity amounts. In future reports, it may be worthwhile to identify separately the firm and non-firm Refusals. It may also provide more insight if the number of MWhs are totaled for firm and non-firm Refusals associated with lack of ATC and whether requests are made for on or off-peak seasonal periods. Not all Paths with Refused requests are listed for each Transmission Provider. Only the five Paths having the most Refused requests for each Transmission Provider are listed. In some cases, there were fewer than five paths having Refused requests.

The analysis was limited to the months of January 1997 and August 1997. These were selected as representing heavy winter and summer loading months. Future analysis could include analysis of other months such as spring with heavy Northwest hydro runoff and/or fall. As data becomes more readily available, OASIS Refusals could be presented for all months to give a more complete assessment for each path.

The information in this report was obtained from the following Transmission Providers and OASIS nodes:

**TABLE VII****WESTERN INTERCONNECTION OASIS NODES**

<b>OASIS NODE</b>	<b>TRANSMISSION PROVIDER</b>
<b>Northwest OASIS</b>	Bonneville Power Administration
	Portland General Electric
	Seattle City Light
	Montana Power Company
	BC Hydro
	Washington Water Power Company
	Snohomish PUD
<b>Southwest OASIS</b>	Salt River Project
	San Diego Gas & Electric
	Sacramento Municipal Utility District
	Public Service of New Mexico
	Northern California Power Authority
	El Paso Electric Company
	Sierra Pacific
	Southern California Edison Company
	Nevada Power Company
<b>Idaho Power OASIS</b>	Idaho Power Company
<b>PacifiCorp OASIS</b>	PacifiCorp
	Deseret G & T
<b>Western OASIS</b>	Western Area Power Administration
	Tucson Electric
	Utah Associated Municipal Power Systems
	Arizona Electric Power Cooperative
	Texas - New Mexico Power Company
<b>Colorado OASIS</b>	Public Service of Colorado
	Tri-State G & T
	Platte River
	WAPA - Rocky Mountain
	West Plains Energy
<b>Los Angeles Department of Water &amp; Power OASIS</b>	Los Angeles Department of Water & Power
<b>Pacific Gas &amp; Electric OASIS</b>	Pacific Gas & Electric
<b>Puget Sound Energy OASIS</b>	Puget Sound Energy
<b>Arizona Public Service OASIS</b>	Arizona Public Service Company

These OASIS sites can be accessed from the WSCC Web Site, <http://www.wsc.com/rinpage.htm>

**TABLE VIII**

**OASIS POSTED REFUSALS OF REQUESTS  
FOR TRANSMISSION CAPACITY**

**For Months of January 1997 & August 1997  
Top 5 paths per Provider**

Provider	Line / Path	# of Jan. Request	# of Jan. Refusals (See Note)	# ATC Refusals in Jan. > 50 MW	# of Aug. Request	# of Aug. Refusals (See Note)	# ATC Refusals in Aug. > 50 MW
AEPC	None	Not Available	0	0	0	0	0
APS	Mead 500 / P. Verde 500	0	0	0	62 for all Paths	2 (2)	0
	FC 345 / N. Gila 500	0	0	0		1 (0)	0
	FC 345 / FC 230	0	0	0		1 (0)	0
	Navajo 500 / P. Verde 500	0	0	0		1 (0)	0
BC Hydro	Westwing 500 / Mktplace 500	0	0	0		1 (0)	0
	BC to PNW	N.A.	N.A.	N.A.	302 for all Paths		
	BC to Alberta	N.A.	N.A.	N.A.			
BPA	BPA to BC Hydro	4 for all Paths	0	0	86 for all Paths	4	0
	BPA to IPC (Lagrande)		0	0		4	0
	BPA share of AC Pacific Interlie		1	0		1	0
	BPA to MidC.		0	0		1	0
El Paso	EPE control/HIDG	4	3 (0)	0	3	1 (1)	0
	Four C / San Juan	0	0	0	1	1 (1)	0

TABLE VIII (Continued)

Provider	Line / Path	# of Jan. Request	# of Jan. Refusals (See Note)	# ATC Refusals in Jan. > 50 MW	# of Aug. Request	# of Aug. Refusals (See Note)	# ATC Refusals in Aug. > 50 MW
Idaho Power		N.A.	N.A.	N.A.	1800 Queued for all Paths	98 for all Paths	N.A.
Montana	MPC to BPA		0	0	319 for all Paths	3	0
	MPC to PEO Yellowtail		0	0		3	2
	MPC to WAPA		1	0		1	0
	MPC to WWP		1	1		1	1
Nevada Power	El Dorado to Mead	168 for all Paths	2(2)	2	42 for all Paths	0	0
	Red Butte to Harry Allen		7(1)	0		6(0)	0
	Navajo - McCullough		2(0)	0		0	0
	Harry Allen - McCullough		2(0)	0		0	0
Pacific Gas & Electric	Not Available	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Pacificorp	Utah / APS	4199 for all paths	35 (32)	32	494 for all Paths	9 (5) 7	1
	IPC / Utah		15 (10)	10		1 (1)	0
	Brg / Wyoming		8 (7)	7		0	0
	Utah / Sierra		8 (8)	6		1 (1)	1
	COB / PACW		7 (7)	3		0	0
	Utah / Nevada		5 (3)	3		33 (30)	30
PGE	PGE share of AC Pacific Intertie	60 for all Paths	2 ;	1	230 for all Paths	4	1
PNM	FCN SJN to WNM ABQ	146 for all Paths	7(4)	4	148 for all Paths	3(0)	0
	SJN to GRN		1(1)	0		4(0)	0

TABLE VIII (Continued)

Provider	Line / Path	# of Jan. Request	# of Jan. Refusals (See Note)	# ATC Refusals in Jan. > 50 MW	# of Aug. Request	# of Aug. Refusals (See Note)	# ATC Refusals in Aug. > 50 MW
PNM	ABQ to SPS		2(0)	0		0	0
	SJN_WMN		0	0		1(0)	0
	ABQ to NEA						
PSCo	all paths	91 for all Paths	0	0	28 for all Paths	0	0
	J. Day / COB		1 (0)	0		5 (2)	1
Puget Sound Energy							
Salt River	4 Com 230 / 4 Com 345	60 for all Paths	3(0)	0	228 for all Paths	0	0
	Mead 230 / PV		0	0	129	11(3)	0
	PP / PV		0	0	2	1(0)	0
	PV / West wing				18	2(0)	0
SCE	4 Com / SCE	308 for all Paths	16 (4)	4	201 for all Paths	0	0
	COB / SCE		11 (6)	6		0	0
	NOB / PVD		5 (4)	4		0	0
	PVD / SON		7 (2)	2		0	0
	COB / PVD		5 (3)	3		0	0
SDG&E	SDG&E to SONGS	120 for all Paths	4(3)	3	50 for all Paths	0	0
	SONGS to NOB		7(5)	5		0	0
	SONGS to COB		1(1)	1		0	0
	SDG&E to CFE		2(0)	0		0	0

**TABLE VIII (Continued)**

Provider	Lline / Path	# of Jan. Request	# of Jan. Refusals (See Note)	# ATC Refusals in Jan. > 50 MW	# of Aug. Request	# of Aug. Refusals (See Note)	# ATC Refusals in Aug. > 50 MW
Sierra Pacific	Sierra/Gonder IPP	15	3 (0)	0	206 for all Paths	0	0
	Sierra/Gonder-Pavant	7	1 (0)	0	27	4 (0)	0
	Midpoint/Gonder-Pavant	6	2 (0)	0	95	10 (5)	5
	Control/Gonder-IPP	2	2 (0)	0	3	1 (0)	0
	Gonder-Pavant/Summit	2	2 (0)	0	0	0	0
TNP	None	Not Available	0	0	0	0	0
Tucson	None	Not Available	0	0	4 for all Paths	0	0
UMPA	None	Not Available	0	0	0	0	0
WALC	LIB 345 - MED 345	Not Available	2	0	24 for all Paths	0	0
WAUC	None	Not Available	0	0	0	0	0
WASN	None	Not Available	0	0	0	0	0
WWP	WWP to IPC	N.A.	0	0	43 for all Paths	16 (0)	0
	WWP to MidC	N.A.	0	0		9 (0)	0
	WWP to MPC	N.A.	0	0		9 (0)	0
	WWP to BPA/E	N.A.	0	0		2 (0)	0

**Notes:** - Number inside the parenthesis represents the total number of path refusals due to lack of ATC  
- Number outside the parenthesis represents the total number of path refusals for any reason  
- If there is no parenthetical number, the cause of the refusal could not be determined from the posted OASIS information.  
- N.A. = Information Not Available

## 5. Paths with OASIS postings of ATC=0

Transmission Providers were requested to indicate which major Paths had ATC=0 posted at some time during the months of January and August, 1997. This information is important because it indicates that a path may be fully subscribed for some services offered. Non-firm capacity is often available when firm ATC = 0. With a posting of zero ATC, Users may choose to not request capacity and there may be few if any Refusals even though the path is fully subscribed. Therefore, information on Paths with posted ATC = 0 and information on Paths with Refused service requests are both important to developing a more complete picture of the availability of capacity on a given Path.

Table IX below indicates the Paths or lines that were reported by the Transmission Providers as having firm ATC=0 postings in either January or August, 1997 (responses were not received from all Transmission Providers):

**TABLE IX**  
**PATHS WITH OASIS FIRM ATC=0 POSTINGS**  
**Months of January 1997 and August 1997**

TRANSMISSION PROVIDER	MONTH	PATH	COMMENTS
Bonneville Power Adm.	August	West of Hatwai, E to W	
		BPA to LaGrande (Idaho Power)	
		LaGrande to BPA	
		Pacific AC Intertie, N to S	
		Pacific DC Intertie, N to S	
Puget Sound Energy	January	Mid Columbia to Puget	
		Colstrip to Garrison	
		Centralia to Puget	
		BPA to Puget	
	August	Colstrip to Garrison	
		Centralia to Puget	
Public Service of New Mexico	January & August	Albuquerque to El Paso Electric	
		SNJ/WNM/ABQ/ABQ - NEA	
		SPS - ABQ	
		WW - Four Corners	
BC Hydro	August	BCH to Alberta	ATC = 0 19% of time
Public Service of Colorado	January & August	TOT 5 W to E	
		TOT 3 N to S	
PacifiCorp	January & August	PacifiCorp to COB	

**TABLE IX (Continued)**

TRANSMISSION PROVIDER	MONTH	PATH	COMMENTS
		COB to PacifiCorp	
		Idaho Power to PacifiCorp West	
Platte River	Not Specified	Craig to Ault	TOT 5 W to E
		Craig to Blue River	TOT 5 W to E
		Ault to St. Vrain	TOT 7 N to S
West Plains Energy	January & August	none	No ATC=0 postings
Arizona Public Service	Not Specified	Four Corners 345 to Cholla 345	
		Cholla 345 to Pinnacle Peak 345	
		Palo Verde 500 to Westwing 500	
		Palo Verde 500 to North Gila 500	
		Mead 500 to Westwing 500	Both directions
		Mead 500 to Mead 230	
Salt River Project	Not Specified	Navajo to McCullough	
		Four Corners 345 to Coronado	Both directions
		Liberty to Mead 230	
		Palo Verde to Coronado	
		Palo Verde to Hayden (AZ)	
		Palo Verde to Mead 230	
		Palo Verde to Pinnacle Peak	
		Palo Verde to Westwing	
		Silver King to Hayden (AZ)	
		Westwing to Marketplace	
		Westwing to Mead 230	
		Westwing to Mead 500	
El Paso Electric	Not Specified	EPE Control to Arts 345/230	
		EPE Control to Picho 115/24	
		Four Corners 345 to West Mesa 345	
		Springer 345 to Arts 345/230	
		Luna 345/115 to EPE Control	
		Hidg 345/115 to EPE Control	
		Amrad 115 to EPE Control	
		Picho 115/24 to EPE Control	
Tri State G & T	January & August	Craig to Bonanza	Tri State posted ATC=0 on all its paths for January & August
		Bonanza to Craig	
		Craig to San Juan	Both directions
		Craig to Ault	Both directions
		Craig to Midway	
		Craig to Blue River	

## **C. SUMMARY OF RELIABILITY AND COMMERCIAL USES**

This Plan has assessed the reliability of the Western Interconnection transmission system based upon WSCC reliability studies of the bulk power system. The Plan has also assessed the ability of the transmission system to meet the commercial needs of Users based upon posted OASIS information and the actual capacity loadings on the major interconnection paths in the Western Interconnection.

Table X summarizes this assessment for several of the major paths in the Western Interconnection. Only those Paths for which there was complete information are summarized in Table X. Additional information on these and other Paths is included in Tables IV, V, VIII and IX. In addition, Table X notes whether there are currently plans for increasing Path capacity, as reflected by the Proposed projects in Section IV and Appendix A of this Plan or whether there are closely related Proposed Projects.

The Projects in Appendix A are primarily subtransmission level projects. The WSCC and OCSG reliability assessment in this Plan is primarily a bulk system reliability assessment. In addition, the reliability studies by the OCSG are performed to assess the reliability of the existing system and the existing path transfer ratings. These studies are not performed to identify new projects or to provide economic justification for new projects. Therefore, the information in this Plan does not demonstrate a clear linkage between the reliability and commercial assessment of the existing system in Section III and the Proposed Projects in Section IV and Appendix A. Future Plans may address the "needs" analysis differently to improve the causal relationship between proposed projects and needs.

From the information presented in this Plan, it cannot be concluded at this time that the capacity of any transmission path in the Western Interconnection should be upgraded. Rather, this Plan provides information on the uses being made of the major transmission paths. It is the responsibility of the Transmission Providers and the Transmission Users to use this and other information to assess the cost and benefits of capacity expansion. The results of this assessment are not meant to imply that it is economic to replace existing facilities or to construct new facilities.

The following identifies the information contained in Table X:

**Column 1** lists the major paths that are summarized in this report and summarized in the table.

**Column 2** identifies those major paths which have experienced a reduction in Operating Transfer Capability (OTC) related to reliability concerns with operation at the Rated Transfer Capability.

**Column 3** identifies whether the Paths have exceeded 75% or 90% of their rating. This is based upon the information shown in Table V. The rating is assumed as OTC if that information was available. This was only available for the AC Pacific Intertie. Otherwise the rating is assumed to be the RTC for the Path. The effect of simultaneous operating constraints is not factored in except for the Pacific AC Intertie because this information was not available. In future reports, it would be helpful to collect OTC values for the paths reflecting simultaneous limits, system outages, etc. to provide more meaningful utilization information.

**Column 4** identifies Paths that have experienced Refused transmission service requests as posted on the Transmission Provider's OASIS sites. (This information could be more readily obtained from the OASIS sites in the future if each transmission line posted on the OASIS is identified with a particular Path. Transmission Users expressed this concern in response to the Western Interconnection ATC survey.) This information is contained in Table VIII.

**Column 5** identifies those Paths that have had firm ATC postings of zero at some time during the months of January or August 1997. This information was obtained from the Transmission Providers and is shown in Table IX.

**Column 6** identifies those transmission paths in the Western Interconnection on which Transmission Users reported they have experienced congestion during 1997. This information was reported in response to the Western Interconnection ATC Survey in November 1997.

**Column 7** identifies those transmission Paths on which there are conceptual or proposed projects to increase capacity. This information is taken from the list of projects submitted to the RTAs by Transmission Providers.

TABLE X

**SUMMARY OF MAJOR TRANSMISSION PATH  
RELIABILITY AND COMMERCIAL USE ANALYSIS**  
Within the Western Interconnection

PATH	Has a Reliability concern Derated the Path?	Have Flows or Schedules Exceeded 75/90% of Path Rating?	Have there been Refused Requests Involving the Path? (See Note 8)	Have there been postings of zero Firm ATC on the Path? (See Note 8)	Have Users reported Congestion involving the Path?	Are there conceptual or proposed plans to increase Path capacity?
California - Oregon Inter tie	Yes	Yes / Yes	Yes	Yes	Yes	No - See Note 7.
Pacific DC Inter tie	No	Yes / Yes	Yes	Yes	Yes	No
East of Colorado River	No	Yes / No	Yes	Yes	Yes	No - See Note 5.
Four Corners Area	No	Yes / No	Yes	Yes	Yes	Yes - See Note 6.
Idaho - Northwest	No	No / No	Yes	Yes	Yes	No - See Note 4.
Idaho Area Brownlee - Boise	No	Yes / Yes	Yes	Yes	Yes	Yes - See Note 4.
IPP DC Line	No	Yes / Yes	No	No report	No	No
Midway-Vincent	Yes	Yes / No	Yes	Yes	Yes	No - Note 3. Regarding Path 15
Montana - Northwest	No	Yes / Yes	Yes	No report	No	No

**TABLE X (Continued)**

PATH	Has a Reliability concern Derated the Path?	Have Flows or Schedules Exceeded 75/90% of Path Rating?	Have there been Refused Requests Involving the Path? (See Note 8)	Have there been postings of zero Firm ATC on the Path? (See Note 8)	Have Users reported Congestion Involving the Path?	Are there conceptual or proposed plans to increase Path capacity?
TOT 1A (Colorado - Utah)	No	Yes / No	No	Yes	No	No
TOT 2A (Colorado - NM)	No	No / No	No	Yes	Yes	Yes - Note 1.
TOT 2B (Utah - Ariz/NM)	No	No / No	Yes	No	Yes	Yes - Note 2.
TOT 2C (Utah - Nevada)	No	Yes / Yes	Yes	No report	No	Yes - Note 2.
TOT 4A (Wyoming)	No	No / No	Yes	No	Yes	No

Note 1. - See Northeast New Mexico Reinforcement Project, page 68.

Note 2. - See SWIP Project, page 74

Note 3. - See PG&E sponsored Los Banos - Gates 500 kV Project in Appendix A, California Project Summary Tables, page 121. This Project will increase the capacity of WSCC Path 15, but not the capacity of Midway - Vincent.

Note 4. - See Brownlee - Boise Project on page 71. This project will not increase capacity of the Idaho - Northwest Path, but will increase capacity east of the Idaho - Northwest Path

Note 5. - Capacity of East of Colorado River was increase from 5700 to 7550 MW in 1996.

Note 6. - See "Shiprock - Four Corners 345 kV Interconnection Project" in Appendix A, Arizona Project Summary Tables, page 104.

Note 7. - Several hundred MVAR of shunt compensation has been added in the Northwest since 1996 to provide voltage support to the California - Oregon Intertie project

Note 8. - Many of the listed Paths are not posted on the OASIS sites on a Path basis; rather the individual owners in the Path post ATC based upon their individual ownership shares. Therefore a "Yes" may indicate an owner posted ATC=0, but the path as a whole may have had available capacity.

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ACC DOCKET NOS. E-01933A-98-0471, E-01933A-97-0772

AG'S REQUEST NO. 29

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REQUEST: State why under the Agreements, TEP, rather than an independent third company, is being set up as the Transco or monopoly transmission company.

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RESPONSE By: Vincent Nitido  
Title: Vice President and Assistant General Counsel

TEP is divesting its interest in Navajo and Four Corners. It must receive adequate consideration for such divestiture. It is unclear how an "independent third party company" would compensate TEP for the assets. In TEP's opinion, the transaction contemplated with APS will provide consideration equal to the fair market value of the assets. The transmission assets will be acquired by a TEP subsidiary, but the assets will be operated by an Independent System Operator. FERC will continue to maintain regulatory supervision of the assets.

AG'S REQUEST NO. 14

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**REQUEST:** Identify each generating unit that is, in whole or in part, owned or leased or operated by APS or TEP and that is, or during the next five years is reasonably likely to be, a must run unit.

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**RESPONSE** By: Mike Flores  
Title: Manager, System Control

Irvington #1
Irvington #2
Irvington #3
Irvington #4
Irvington Combustion Turbine #1
Irvington Combustion Turbine #2
North Loop Combustion Turbine #1
North Loop Combustion Turbine #2
North Loop Combustion Turbine #3.

There is an additional must-run Combustion Turbine proposed for installation in the Tucson area within the next five years.

AG'S REQUEST NO. 15

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**REQUEST:** For each such must run unit, explain (I) why it is a must run unit (e.g., to meet local load given an import constraint, or to supply reactive power), (ii) the conditions under which it is a must run unit, and (iii) the number of hours during each month of the year that it is likely to be must run.

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**RESPONSE** By: Mike Flores  
Title: Manager, System Control

Per NERC/WSCC requirements all Control Areas shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. The remote location of generation resources cause major transfers of energy on the TEP bulk power system to the load center. TEP's remedial action scheme is used for double contingencies for loss of critical path elements to the TEP load center. Incorporated into the transfer capability to the TEP load center are must-run local generation scenarios for reactive support and other selective reactive power supply relaying initiate schemes.

Attached are the tables currently used for the aforementioned remedial action scheme.

The number of hours during each month that must-run is on for these reasons is as follows:

Irvington #1	169
Irvington #2	189
Irvington #3	77
Irvington #4	662
Irvington Combustion Turbine #1	15
Irvington Combustion Turbine #2	12
North Loop Combustion Turbine #1	5
North Loop Combustion Turbine #2	5.5
North Loop Combustion Turbine #3	4.3

ACC DOCKET NOS. E-01933A-98-0471, E-01933A-97-0772

AG'S REQUEST NO. 18

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**REQUEST:** For each generating unit that is, in whole or part, owned or leased or under the control of APS or TEP, identify all load pockets including that unit that exist or are likely to exist for some or all hours of the year.

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**RESPONSE** By: Mike Flores  
Title: Manager, System Control

For TEP, the generating units located within TEP's service territory operate as must-run units to meet the local load within the boundaries of TEP's service territory. Effectively, for TEP, there is a single "load pocket" which is TEP's service territory.

AG'S REQUEST NO. 23

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**REQUEST:** Under the terms of the Settlement Agreements and any other applicable rules:

- a) Is there any restriction on which entities can purchase TEP's "local" generating units (units other than Navajo and Four Corners), provided the entities in question are the highest bidders?
  - b) Specifically, can each of the following purchase TEP's local generating units:
    - (i) a TEP affiliate, (ii) APS, (iii) an APS affiliate, (iv) any other entity (aside from TEP) that owns generation or transmission assets in Arizona?
  - c) Is there any restriction that would prevent any single entity from buying all TEP assets that will be auctioned?
  - d) Is TEP free to auction its generating plants as a single package, even though doing so would exclude from the bidding non-affiliated entities that might otherwise submit the highest bids for individual units? If not, what restrictions exist on how TEP would be allowed to package the units?
- 

**RESPONSE** By: Vincent Nitido

Title: Vice President and Assistant General Counsel

- (a) No, subject to ACC Decision No. 60977 which limits an Affected Utility from acquiring the assets if it would result in such Affected Utility owning more than 40 percent of the state's total generation megawatts of capacity. In addition, FERC approval will be required to transfer any generation assets. On aspect of such approval is a market power analysis, which could serve as a basis for denial of the transfer if FERC determines the proposed purchaser would have market power in the applicable region. TEP has advised the ACC Staff that its affiliates will not bid on TEP generation assets.
- (b) See (a) above.
- (c) See (a) above.
- (d) No, the Auction Protocols submitted to the ACC Staff call for the assets to be auctioned off separately. Bidders may bid on any or all of the assets.

AG'S REQUEST NO. 24

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**REQUEST:** Suppose that an entity other than the ACC (e.g., FERC, acting under the Federal Power Act, or a federal antitrust agency, the Arizona Attorney General, or a private party, seeking to enforce the Clayton Act) rejects or successfully challenges a purchase by the highest bidder for some or all of TEP's local generation assets. In that case, will TEP be permitted to retain ownership of the generating units in question and recover 100% of stranded costs?

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**RESPONSE** By: Vincent Nitido  
Title: Vice President and Assistant General Counsel

While the auction protocols do not specifically address that situation, it is TEP's position that the units would be sold to the next highest bidder, subject to the ACC's ability to declare a failed auction with respect to the assets, and subject further to the requirement that the sale to the next highest bidder be accomplished prior to the completion of the securitization transaction.

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# AUCTION PROTOCOLS

## For the Auction of Certain Electric Generation Assets of Tucson Electric Power Company

October 1, 1998

### 1. Introduction

Tucson Electric Power Company ("TEP" or the "Company") is seeking to sell through an auction process (the "Auction") its interests in the generating facilities set forth in Section 5 hereof (individually, a "Facility" and collectively, the "Facilities"). The Facilities are more fully described in the Company's Offering Memorandum dated \_\_\_\_\_ (the "Offering Memorandum"), which has been provided to each prospective Bidder.

Prospective Bidders who have executed and delivered TEP's Confidentiality Agreement are entitled to submit bids in accordance with these Auction Protocols. The sale of each Facility will be pursuant to definitive Purchase and Sale Agreements or Assignments (the "Definitive Agreements") and other related contracts entered into between TEP and the Winning Bidder.

The sale of each Facility following the completion of the Auction is subject to the approval of the Arizona Corporation Commission ("ACC"). Immediately following the execution of Definitive Agreements by TEP and the Winning Bidder, TEP will submit the Definitive Agreements to the ACC for approval.

### 2. Communications with Auction Officers

In order to promote accuracy and consistency of information provided to Bidders from the date hereof until TEP announces or otherwise notifies Bidders that the Auction is terminated or concluded ("concluded" meaning that all regulatory proceedings relating the Auction have concluded), Bidders should direct all submissions, communications and inquiries regarding any aspect of the Auction or the Facilities solely to the Auction Officer at the following address:

Tucson Electric Power Company  
c/o John G. Paton  
New Harbor Incorporated  
280 Park Avenue, East Tower  
New York, New York 10017  
U.S.A.  
Telephone: (212) 453-1168  
Facsimile: (212) 453-1173

In completing this section, Bidder should follow these instructions:

1. Bidder may only submit a Final Bid for the Facility or Facilities for which TEP selected it as a Phase III Bidder. Final Bids on any other Facility or Facilities will not be considered.

2. Providing a Final Bid for **any one** of Bid Nos. 1, 2, 3, 4, 5, 6, 7, 8, 9 or 10 indicates a willingness to purchase only the **single Facility** described.

3. Providing a Final Bid for **two or more** of Bid Nos. 1, 2, 3, 4, 5, 6, 7, 8, 9 or 10 indicates a willingness to purchase any or all of the Facilities for which Final Bids are submitted. The Bidder may be the Winning Bidder for any one of the Facilities, any combination or all of the Facilities on which it bid.

4. Providing a Final Bid for two or more of Bid Nos. 1, 2, 3, 4, 5, 6, 7, 8, 9 or 10 in conjunction with an attachment hereto to the effect that Bidder is only willing to purchase the **combination of the Facilities** described indicates that Bidder has a willingness only to purchase the combination described.

5. A Bidder selected and wishing to bid on **any and all combinations** of the Facilities should submit a Final Bid for all ten Bid Nos.

<u>Bid No.</u>	<u>Facility or Facilities</u>	<u>Final Bid</u>
1.	Springerville	S _____
2.	Irvington	S _____
3.	TEP's 50% interest in Unit 1 of San Juan	S _____
4.	TEP's 50% interest in Unit 2 of San Juan	S _____
5.	TEP's 7% interest in Unit 1 of Four Corners	S _____
6.	TEP's 7% interest in Unit 2 of Four Corners	S _____
7.	TEP's 7.5% interest in Unit 1 of Navajo	S _____
8.	TEP's 7.5% interest in Unit 2 of Navajo	S _____
9.	TEP's 7.5% interest in Unit 3 of Navajo	S _____
10.	TEP's combustion turbines	S _____

2. Additional Information

Attached is a schedule setting forth:

1. Bidder's officer(s) and employee(s) who, in the ordinary course of their duties, have access to information on the matters with respect to which Bidder is required to make best knowledge representations and warranties under the Purchase and Sale Agreement.

ACC DOCKET NO. E-01933A-98-0471

RUCO'S REQUEST NO. 4.10

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**REQUEST:** Settlement Agreement page 5: Could TEP declare a failed auction, or would only the ACC have the authority to do so?

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**RESPONSE** By: Vincent Nitido  
Title: Vice President and Assistant General Counsel

TEP cannot declare a failed auction. If TEP chooses not to divest a generating asset, it may only recover transition revenues under IV F. of the Settlement Agreement.

ACC DOCKET NO. E-01933A-98-0471

**RUCO'S REQUEST NO. 4.11**

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**REQUEST:** Under the Settlement Agreement, if the ACC did not declare a failed auction, but TEP chose not to divest a generation-related asset, what options would TEP have for stranded cost recovery? If this would vary according to the circumstances, then please explain the options under each set of circumstances.

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**RESPONSE** By: Vincent Nitido  
Title: Vice President and Assistant General Counsel

In the unlikely event TEP elects to retain an auctioned asset where the ACC has not declared a failed auction, TEP would be allowed to recover "transition revenues" relating to such asset. The transition revenues methodology is described in "Option No. 2" set forth on page 12 of ACC Decision No. 60977.

RUCO'S REQUEST NO. 5.3

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**REQUEST:** Transco transmission monopoly:

- (a) Please explain the advantages of TEP's transmission affiliate holding a monopoly on transmission in Arizona.
  - (b) Please provide all studies or other papers known to TEP which address the advantages and/or disadvantages of such a monopoly.
  - (c) What advantages are there to TEP's affiliate, Transco, holding the monopoly rather than another company holding the monopoly?
- 

**RESPONSE** By: Vincent Nitido  
Title: Vice President and Assistant General Counsel

- (a) The ACC has expressed concern over the potential of vertical market power as a barrier to retail electric competition in Arizona. The Settlement Agreement with ACC Staff provides for the divestiture by TEP of its generation assets, and contemplates the acquisition by TEP of additional transmission assets. The proposal would remove the possibility of vertical market power being asserted by either TEP or APS. Transmission owned by TEP's subsidiary would continue to be regulated by FERC, and operated by an Independent System Operator.
- (b) TEP is unaware of any such studies or papers.
- (c) TEP is divesting its interest in Navajo and Four Corners. It must receive adequate consideration for such divestiture. In TEP's opinion, the transaction contemplated with APS will provide consideration equal to the fair market value of the assets. In addition, the transaction will address the ACC's concerns regarding vertical market power (see (a) above).

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**DATA REQUESTS FROM OFFICE OF THE ATTORNEY GENERAL  
DOCKET NO. E-01345A-98-0473, E-01345-97-0773 & RE-00000C-94-0165  
SECOND SET OF DISCOVERY REQUESTS**

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**QUESTION 1:** Identify each of your simultaneous and non-simultaneous transmission capacities and transfer capabilities into and out of the State of Arizona.

**RESPONSE:** Answers to Questions 1-6 are represented in Table #1 below:

**TABLE 1**

TRANSMISSION TIES	Capacity		LIMIT/ FACILITY	CONSTRAINT
	IN (MW)	OUT (MW)		
Utah/Colorado/ to APS New Mexico	1340	1340	Four Corners Four Corners-Cholla 345kV lines 1&2	Thermal
Nevada to APS	795	795	Southern 500kV Moenkopi-Yavapai 500kV line & Navajo-Westwing 500kV line	Thermal
California to APS	1458	1318	Palo Verde East Palo Verde-Westwing #1 &2 Palo Verde- Kyrene 500kV line	Thermal
TOTALS	3593	3453		

**QUESTION 2:** Identify each of your simultaneous and non-simultaneous transmission capacities and transfer capabilities into and out of your control area within the State of Arizona.

**RESPONSE:** See response to Question 1.

**QUESTION 3:** Identify each of your simultaneous and non-simultaneous transmission capacities and transfer capabilities into and out of each State contiguous to the State of Arizona.

**RESPONSE:** See response to Question 1.

**QUESTION 4:** Identify each facility that limits or is a constraint upon transmission capacity by name and geographic location.

**RESPONSE:** See response to Question 1.

**DATA REQUESTS FROM OFFICE OF THE ATTORNEY GENERAL  
DOCKET NO. E-01345A-98-0473, E-01345-97-0773 & RE-00000C-94-0165  
SECOND SET OF DISCOVERY REQUESTS**

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**QUESTION 11:** Produce all transmission studies or other documents that deal with limits or constraints on transmission into our out of Arizona and into our out of your control area within Arizona and into or out of any State contiguous to Arizona.

**RESPONSE:** Due to the voluminous nature of the transmission studies and other documents that deal with limits or constraints are on file, they will be made available to view at the APS Transmission Operations Center located at 502 South 2<sup>nd</sup> Avenue.

**QUESTION 12:** Produce all reliability studies including, but not limited to all WSCC studies.

**RESPONSE:** Due to the voluminous nature of the reliability studies, they will be made available to view at its Transmission Operations Center located at 502 South 2<sup>nd</sup> Avenue.

**QUESTION 13:** Produce your "path rating book" or any other document that provides transmission capacity information.

**RESPONSE:** APS refers to the "path rating book" as the "Arizona Security Monitoring Manual", a copy of which is enclosed.

**QUESTION 14:** Produce any studies prepared by any third party such as consultants or experts regarding transmission constraints or capacity created from 1994 to the present.

**RESPONSE:** No outside consultants or experts have performed transmission studies on behalf of APS since 1993.

**QUESTION 15:** Identify each transmission facility and state the simultaneous and non-simultaneous capacity of each.

**RESPONSE:** Four Corners System:

Four Corners-Cholla 345kV lines #1 & 2  
Cholla-Pinnacle Peak 345kV lines #1 & 2  
Cholla-Saguaro 500kV line

Southern 500kV System:

Navajo-Moenkopi 500kV line  
Navajo-Westwing 500kV line  
Moenkopi-Yavapai 500kV line  
Yavapai-Westwing 500kV line

Palo Verde East:

Palo Verde-Westwing 500kV lines #1 & 2  
Palo Verde-Kyrene 500kV line  
Palo Verde-North Gila 500kV line

**DATA REQUESTS FROM OFFICE OF THE ATTORNEY GENERAL  
DOCKET NO. E-01345A-98-0473, E-01345-97-0773 & RE-00000C-94-0165  
SECOND SET OF DISCOVERY REQUESTS**

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Westwing-Mead 500kV line

Transmission capacities are listed in TABLE 1.

**QUESTION 16:** Provide, in machine-readable form, all TTC and ATC and related transmission data posted on OASIS regarding transmission capacity including, but not limited to your estimates of transmission capacity for 12 months.

**RESPONSE:** Hourly values for ATC and TTC for the month of November 1998 has been provided in machine readable form on a 3.5" disk. For December 1998 to October 1999, monthly peak values for ATC and TTC have been provided due to no hourly adjustment for ATC or TTC have been made that far in advance.

**QUESTION 17:** Produce every analysis, concerning any electric utility or electric service provider, by whatever name known, and every group of electric utilities or electric service providers relating to a) market power and/or b) the ability to effect prices in any of the following markets within the State of Arizona:

- 1) Transmission
- 2) Distribution
- 3) Generation
- 4) Metering
- 5) Meter reading and customer service

**RESPONSE:** Such analyses as the Company has been provided in Response to Questions 3, 5, 6 and 7 of your First Set of Data Requests.

**QUESTION 18:** Produce every analysis, concerning any electric utility or electric service provider, by whatever name known, and every group of electric utilities or electric service providers relating to a) market power and/or b) the ability to effect prices in any of the following markets within the Western Region of the United States:

- 1) Transmission
- 2) Distribution
- 3) Generation
- 4) Metering
- 5) Meter reading and customer service.

**RESPONSE:** See response to Question 17.

**QUESTION 19:** Identify the person who provided answers to these data requests.

**RESPONSE:** Various employees of APS as well as APS legal counsel contributed to these as well as prior APS responses.

**DATA REQUESTS FROM OFFICE OF THE ATTORNEY GENERAL  
DOCKET NO. E-01345A-98-0473, E-01345-97-0773 & RE-00000C-94-0165  
THIRD SET OF DISCOVERY REQUESTS**

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**QUESTION 1:** Identify all transmission paths involving Arizona or states contiguous to Arizona that are subject to the WSCC Unscheduled Flow Mitigation Procedure, the conditions under which the transmission capacity of each path in each direction is likely to be fully utilized, and the number of hours during which line loading relief or other flow mitigation procedures were applied to each path during 1997 and during 1998. Provide all relevant documents.

**RESPONSE:**

PATH # - Name	CONDITIONS	HOURS OF RELIEF		
		1996	1997	1998
22 – Four Corners West: Four Corners – Moenkopi 500 kV Four Corners – Cholla 345 kV	- High generation at Four Corners - High schedules southwest of Four Corners - Clockwise loop flow	*	24	34
23 – Four Corners 500/345 kV transformer	- Four Corners Unit Five off line - Clockwise loop flow	*	53	15
21 – Arizona to California: Navajo – McCullough 500 kV Moenkopi – Eldorado 500 kV Westwing – Mead 500 kV Palo Verde – Devers 500kV Palo Verde – North Gila 500 kV Liberty – Mead 345 kV	- Full Generation Capacity at Navajo, Four Corners, & Palo Verde - High schedules - Clock wise loop flow	0	0	0

\* APS does not have any records for 1996.

**QUESTION 2:** Identify all cases in which APS or TEP has denied a transmission service request since January 1, 1997. Identify the requesting party, the nature of the requested service (points of origin and delivery, firm or nonfirm, time period, MW), and the reason for the denial. Produce all relevant documents.

**RESPONSE:** See Attachment 1.

**QUESTION 3:** Identify all cases in which APS or TEP requested line loading relief or otherwise curtailed scheduled transfers into, out of, or within Arizona since January 1, 1996. Produce all relevant documents.

**RESPONSE:** Arizona Public Service (APS) does not keep records other than what is required according to the WSCC Unscheduled Flow Mitigation (USFM) Procedures. See table A, question 1.

**DATA REQUESTS FROM OFFICE OF THE ATTORNEY GENERAL  
DOCKET NO. E-01345A-98-0473, E-01345-97-0773 & RE-00000C-94-0165  
THIRD SET OF DISCOVERY REQUESTS**

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**QUESTION 13:** For each of measures listed in question 12. above that was used in 1997-1998, describe in non-technical terms what the measure involves and what effects it has.

**RESPONSE:**

Perkins phase shifters	SRP is the owner of this equipment. APS does not have any records.
Liberty phase shifter	WAPA is the owner of this equipment. APS does not have any records.
Bypassed series compensation	APS does not keep these records
Reduction in scheduled flow so they are within scheduled rights	APS does not allow EOR scheduling to exceed schedule rights
Unscheduled (loop) flow curtailment	See Table A
Out of merit order generation at Navajo	SRP is the operating agent of this facility. APS does not have any records.

**QUESTION 14:** Identify each generating unit that is, in whole or in part, owned or leased or operated by APS or TEP and that is, or during the next five years is reasonably likely to be, a must run unit.

**RESPONSE: Table B**

Must Run Generation Units	Condition	June - September	October - May	Load Pocket	Load Pocket Peak 1998 Load
West Phoenix Combined Cycle units 1,2,&3	Valley 230 kV lines thermal limit and voltage support	400 hrs	0 hrs	Phx	3419 MW
West Phoenix Gas Turbine units 1 &2	Valley 230 kV lines thermal limit and voltage support	400 hrs	0 hrs	Phx	3419 MW
Ocotillo Steam units 1&2	Valley 230 kV lines thermal limit and voltage support	400 hrs	0 hrs	Phx	3419 MW
Ocotillo Gas Turbine units 1&2	Valley 230 kV lines thermal limit and voltage support	400 hrs	0 hrs	Phx	3419 MW
Yuma Gas Turbine units 1-4	Transformer Limitation	1600 hrs	0 hrs	Yuma	257 MW
Fairview Gas Turbine	Radial Source	1 hr	0 hrs	Douglas	30 MW

**DATA REQUESTS FROM OFFICE OF THE ATTORNEY GENERAL  
DOCKET NO. E-01345-98-0473, E-01234-97-0773 & RE-00000C-94-0165  
THIRD SET OF DISCOVERY REQUESTS**

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purchase by the highest bidder for some for all of TEP's local generation assets. In that case, will TEP be permitted to retain ownership of the generating units in question and recover 100% of stranded costs?

**RESPONSE: N/A**

**QUESTION 25:** If the answer to the preceding question is yes, why do the Settlement Agreements not require that an acceptable buyer be found?

**RESPONSE: N/A**

**QUESTION 26:** Identify each generating unit that is (i) under construction in Arizona, (ii) planned for construction in Arizona during the next five years, or (iii) announced for construction in Arizona during the next five years. For each, identify the owner, location, type of plant (e.g., CT, CC), fuel type, MW capacity, status of permitting, and expected completion date.

**RESPONSE:** APS currently has no plans to construct a generating unit in Arizona over the next five years, nor are any new APS generating plants currently under construction in Arizona.

**QUESTION 27:** Produce all internal documents regarding the value of APS's generation assets.

**RESPONSE:** APS objects to this data request on the grounds that it is overly broad and unduly burdensome. APS also objects to this data request on the grounds that the term "value" is vague and ambiguous. To the extent that the data request seeks information regarding generation costs, such costs are reflected in APS' current rates. This generation cost component will be separately identified in APS' unbundled rates. Cost-related detail is set forth in the FERC Form 1 filing provided in response to Data Request No. 11.

**QUESTION 28:** State all circumstances under which TEP or any of its affiliates will own or lease generating capacity or have long-term (over 1 year) contracts for the purchase of generating capacity or energy after 1/1/2001, and identify the generating capacity in question.

**RESPONSE: N/A**

**DATA REQUESTS FROM OFFICE OF THE ATTORNEY GENERAL  
DOCKET NO. E-01345-98-0473, E-01234-97-0773 & RE-00000C-94-0165  
THIRD SET OF DISCOVERY REQUESTS**

**QUESTION 29:** Identify all APS transmission facilities that are subject to a right of first refusal, identify the parties that have a right of first refusal, and identify the terms on which they could exercise a right of first refusal.

**RESPONSE:** Information is attached.

**QUESTION 30:** Please explain the reasoning that supports the statement (under V. Divestiture) that either a region-wide postage stamp approach or a license plate approach will prevent transmission constraints from limiting or frustrating competition.

**RESPONSE:** Under a "postage stamp" or "license plate" ratemaking approach for transmission service, all transmission customers in the region or pricing zone would pay the same rate for transmission service. Either of these pricing approaches would not limit transmission constraints; however, the proposal for treating transmission requests associated with retail direct access is that all Transmission Providers (including APS and TEP) would follow the Committed Uses protocols as developed by the AISA in order to fairly allocate transmission capacity over constrained transmission paths.

This treatment for allocation of transmission capacity over constrained transmission paths, coupled with the license plate ratemaking treatment would serve to mitigate any attempts to limit or frustrate competition insofar as transmission service could be used by a party in order to otherwise accomplish such a goal.

**QUESTION 31:** Please explain and produce documents the support any claim that APS'S control over transmission facilities rated below 345 kV cannot be used to exercise vertical market power. Specifically set forth the pricing for use of these facilities and the capacity of each. Do you claim that the pricing for use of these facilities will be so low and the capacity of these facilities is so large that terms on which these facilities are available for use will not limit competition? State what facts exist to support such a conclusion.

**RESPONSE:** All schedules for load on APS's 230 and 69 kV transmission facilities will be accepted. However, there will be times when a schedule coordinator will be required to purchase their load ratio share of the must run local generation requirement. Must run

pricing will be at a regulated tariff. Thus, any energy service provider can schedule any generation requirement above must run generation and APS will not have any ability to assert vertical market power.

**DATA REQUESTS FROM OFFICE OF THE ATTORNEY GENERAL  
DOCKET NO. E-01345-98-0473, E-01234-97-0773 & RE-00000C-94-0165  
THIRD SET OF DISCOVERY REQUESTS**

which measures were taken to reduce flows on those paths, and explain the measures that were taken and their effects on scheduled transfers into, out of, or within Arizona.

**RESPONSE:**

Path	Number of Hours During 1997 and 1998 Actual Flows were at least 90% of Capacity Limit	
	IN	OUT
Utah/ Colorado/ New Mexico to APS	8/11/97 12 hours 8/12/97 9 hours 6/29/98 1 hours 7/26/98 1 hours	0
Nevada to APS		0
California to APS	0	0

**\* At no time during 1997 and 1998 did actual flows on the paths listed in Table 1 exceed their capacity limit. Therefore, there were zero hours during which measures were taken to reduce flow on the paths.**

**QUESTION 36:** Does Table 1 imply that the simultaneous FCTTC into the State of Arizona is 3,593 MW?

**RESPONSE:** No

**QUESTION 37:** State your best estimates of the FCTTC and FCITC across each interface, and simultaneously across all interfaces combined, into (a) the smallest area that includes Arizona and the Four Corners, San Juan, Mohave, Hoover, Craig, and Hayden plants; (b) Arizona; and (c) the APS control area.

**RESPONSE:** APS and the Western Interconnection do not use the concept of First Contingency Incremental Transfer Capability (FCITC).

- (a) As of April of 1998, the WSCC reported a non-simultaneous import for Arizona / New Mexico transfer capability as 4204 MW.
- (b) As of April of 1998, the WSCC reported a non-simultaneous Arizona import transfer capability as 4684 MW.
- (c) See data request 2, Table 1.

**QUESTION 38:** Produce a copy of each document listed in the APS response to Question 7, with the exception of documents already provided. Making documents



## **New Energy Ventures Opens Arizona-Based NEV Southwest Offices**

Los Angeles, CA (October 29, 1998) - New Energy Ventures has opened its NEV Southwest, L.L.C. offices in Tucson, Arizona, and named former Tucson Electric Power Company manager of retail marketing Phil Harper as its president.

NEV Southwest will have the responsibility to create and service customer opportunities throughout Arizona, Nevada, Utah, Colorado, and New Mexico, as these states move ahead with the plans to open the electric industry to competition. Arizona and Nevada will be the immediate targets for NEV Southwest, with Arizona's competitive market scheduled to begin on January 1, 1999, and Nevada following in December of 1999.

In preparation for the start of the Arizona competitive market, NEV Southwest has filed for a certificate of convenience and necessity (CC&N) with the Arizona Corporation Commission (ACC).

"Strong regional operations are the key to being successful in emerging competitive energy marketplaces," declared Michael R. Peevey, president and chief executive officer of New Energy Ventures. "This region has emerged as an exciting market for our products and services, and we look forward to serving customers here when competition begins next year."

The potential market opportunity for the five state region is estimated to be over 31,000 megawatts of industrial and commercial load, with an annual revenue of approximately \$9.6 billion. NEV Southwest will operate in Tucson and Phoenix, with additional offices opening as other states finalize their frameworks for a competitive marketplace.

"We're very excited to offer the New Energy Ventures line of products and services throughout the southwest," said Phil Harper, president of NEV Southwest. "This region will greatly benefit from competition, and I am pleased that New Energy Ventures is bringing its experience to customers in this new marketplace."

New Energy Ventures, Inc., is a rapidly growing technology-based energy company formed in 1995 to serve customers in every state where a competitive energy market is emerging, including California and the New England, Northeast, Midwest, Mid-Atlantic, and Southwest regions. Its services include energy buying for its customers, energy efficiency services, distributed generation, and low-cost supply of energy-related equipment and supplies. With headquarters in Los Angeles, New Energy Ventures has regional offices in Boston, Chicago, New York, Philadelphia, Phoenix, Tucson, and the San Francisco Bay area. As competitive energy markets develop in other states, New Energy Ventures will continue to expand nationally. New Energy Ventures is 50 percent owned by UniSource Energy Corporation (NYSE: UNS), and 50 percent owned by New Energy Holdings, L.L.C. (which is owned by the senior officers of New Energy Ventures).

## NEV SECURES LOW COST PACIFIC NORTHWEST POWER

New Energy Ventures, Inc. (NEV) and the Bonneville Power Administration (BPA) in mid-August announced a joint power transaction that will make excess federal power from the Pacific Northwest available to California electricity users. The announcement was made by NEV President, Michael R. Peevey and BPA Deputy Administrator/ CEO, Jack Robertson.

NEV and BPA will work cooperatively to pursue and serve commercial, industrial, state and federal clients in California's new deregulated electricity marketplace. BPA will provide power as well as other support services to NEV. Under the new arrangement an initial sale to NEV of 200 megawatts (MW) of electricity a year for five years has been made with options that can increase this amount to 700 MW. NEV will use this power to serve both individual clients and aggregated groups of clients.

In addition to the specific power sales agreement, BPA and NEV have agreed upon a series of business principles that include:

- NEV and BPA will decide when and where it is appropriate and in their mutual benefit to work together to arrange power services for a particular client or group of clients.
- NEV and BPA will maintain an ongoing and active working relationship. Each will also respect the other's right to work independently to secure power sales commitments.
- NEV and BPA agree to set terms and conditions for BPA to serve as a primary supplier of NEV's energy, ancillary and other related services needs.
- NEV and BPA have agreed to terms and conditions for NEV's purchase of blocks of economy and seasonal energy.

"This agreement is a win/win/win proposition for the Pacific Northwest, California and the environment," said BPA's Robertson. "The California consumers represented by NEV will have access to one of the lowest cost, hydroelectric-based firm power supplies available, with that low cost guaranteed for the next five years."

New federal regulations now make it possible for BPA to make sales of surplus power, power above and beyond that needed to meet the needs of its Pacific Northwest customers, under long-term power supply contracts without some of the prior restrictions that limited the market value of such power.

"This is a perfect example of what the California Public Utilities Commission deregulation decision is all about—lower cost electricity supplies for California consumers," said NEV President Peevey. "The potential for

consumers to benefit from lower prices and for the California economy to prosper as businesses reduce operating costs and increase profitability is enormous."

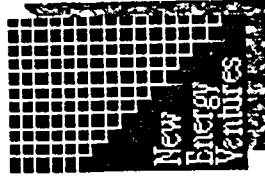
Both executives are enthusiastic about the added advantage of serving California consumers with "green" power, electricity generated from renewable hydroelectric resources. "Hydroelectric power does not carry the fuel supply price or carbon tax risk that is associated with most other power sources," according to Robertson. "Furthermore," he said, "our federal hydroelectric projects in the Northwest will continue to produce low-cost renewable energy for decades to come."

Peevey believes that in addition to being "green," BPA power will be attractive to customers because it is a low-cost, stable and reliable power source. "All of the benefits of BPA power are long-term," Peevey said, "BPA and its Pacific Northwest customers enjoy the lowest power rates in the country."

Peevey and Robertson agree that the long-term success of the NEV and BPA partnership is assured by the strong consumer orientation and commitment to competitive market principals of both organizations. "When you deal with BPA, you are dealing with a public agency that operates solely for the benefit of its customers and constituents. Making BPA surplus power available to NEV will help lower power rates for California and the Northwest consumers," said Robertson.

Deliveries of power by BPA to the California-Oregon Border will begin by January 1, 1998, the date the CPUC has said retail access will take effect in California. NEV's current slate of clients includes the Association of Bay Area Governments, the California Retailers Association, the Building Owners and Managers Association, the Society of Plastics Industries, universities, hospitals, and a large number of individual companies.

[[Related Links](#) | [Customer Service](#) | [Home](#) | [How to Contact NEV](#)]



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RECEIVED

JUN 24 1998

Re: Stranded Costs  
and  
Diversification

Arizona Corporation Commission

DOCKETED

ANTITRUST

BEFORE THE ARIZONA CORPORATION COMMISSION

JUN 22 1998

JIM IRVIN  
COMMISSIONER - CHAIRMAN  
RENZ D. JENNINGS  
COMMISSIONER  
CARL J. KUNASEK  
COMMISSIONER

DOCKETED BY

C.M.

IN THE MATTER OF THE COMPETITION IN  
THE PROVISION OF ELECTRIC SERVICES  
THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. RE-00000C-94-0165

DECISION NO. 60977

OPINION AND ORDER

DATES OF HEARING:

December 9, 1997 and February 5, 1998 (Procedural  
Conferences); February 9, 10, 11, 12, 13, 17, 18, 19, 20,  
23, 25, 26 and 27, 1998

PLACE OF HEARING:

Phoenix, Arizona

PRESIDING OFFICER:

Jerry L. Rudibaugh

IN ATTENDANCE:

Renz D. Jennings, Commissioner  
Carl J. Kunasek, Commissioner

APPEARANCES:

Mr. Steven M. Wheeler, Mr. Thomas L. Mumaw and Mr.  
Jeffrey B. Guldner, SNELL & WILMER, LLP, on behalf  
of Arizona Public Service Company;

Ms. Deborah R. Scott and Ms. Teena Wolfe, on behalf of  
the Residential Utility Consumer Office;

Mr. Raymond S. Heyman, ROSHKA, HEYMAN &  
DEWULF, P.C., and Mr. Bradley S. Carroll, on behalf of  
Tucson Electric Power Company;

Mr. Craig A. Marks, on behalf of Citizens Utilities  
Company;

Mr. Lex J. Smith, BROWN and BAIN, P.A., on behalf of  
Ajo Improvement Company, Morenci Water and Electric  
Company, and Phelps Dodge Corporation;

Mr. Michael M. Grant, GALLAGHER & KENNEDY, on  
behalf of Arizona Electric Power Cooperative, Graham  
County Electric Cooperative, and Duncan Valley Electric  
Cooperative;

Mr. Walter W. Meek, President, on behalf of Arizona  
Utility Investors Association;

Mr. Norman J. Furuta, on behalf of the Department of the  
Navy;

## DISCUSSION

### Introduction

Pursuant to Decision No. 59943, the Commission approved a phase-in transition to a competitive generation electric power market commencing on January 1, 1999. In the long-run, it is believed that competition will result in lower prices, better service, more choices and increased innovation. However, the transition from regulated monopoly to a competitive market has raised some contentious issues. One of the primary issues is who should pay for the costs associated with the transition from a cost-based regulated environment to a market environment. The Affected Utilities<sup>2</sup> have claimed a reliance on building large baseline generation plants/long-term power contracts to provide electric service for all those who desired service for a promise of regulated returns over the life of the plant. This is in conflict with market priced rates, especially during a period of excess generation capacity in the Southwest Region. According to APS, there will be excess capacity up through 2006. The difference between market based prices and the regulated cost of power has been generally referred to as "stranded costs". Rates that customers pay today include 100 percent recovery of stranded costs. These stranded costs consist of the following general categories: Generation related assets; Regulatory assets; and Social costs.

Pursuant to the Electric Competition Rules, the Group developed recommendations for the analysis and recovery of stranded costs. The Group held its initial meeting on March 4, 1997. There were several other meetings held during 1997, culminating in a Working Group Report on September 30, 1997. Because of the complexity of the stranded cost issue as well as the diversity of interests, there was little consensus reached by the Group. As a result, an evidentiary hearing was established to address the stranded costs issues.

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<sup>2</sup> Pursuant to R14-2-1601(1), "Affected Utilities" means the following public service corporations providing electric service: Tucson Electric Power Company, Arizona Public Service Company, Citizens Utilities Company, Arizona Electric Power Cooperative, Trico Electric Cooperative, Duncan Valley Electric Cooperative, Graham County Electric Cooperative, Mohave Electric Cooperative, Sulphur Springs Valley Electric Cooperative, Navajo Electric Cooperative, Ajo Improvement Company, and Morenci Water and Electric Company.

**ARIZONA PUBLIC SERVICE COMPANY**

**1998 -- 2007**

**TEN-YEAR PLAN**

Prepared for the

**Arizona Corporation Commission**

January 1998

**ARIZONA PUBLIC SERVICE COMPANY  
1998 – 2007  
TEN-YEAR PLAN**

**GENERAL INFORMATION**

This annual *Ten-Year Plan* is filed with the Arizona Corporation Commission (ACC) in compliance with Arizona Revised Statutes, Section 40-360.02, pertaining to the siting of electric power generating units and transmission lines. The *Ten-Year Plan* describes the plans of Arizona Public Service Company (APS) to construct or begin to construct, within the ten-year interval from 1998 to 2007, generating units of one hundred million watts (100 MW) or greater capacity and transmission lines having more than two spans of one hundred and fifteen thousand volts (115 kV) or higher voltage.

APS projects that the only significant generating capacity for which construction is scheduled to begin in 2007 or earlier will be four annual installments of approximately 178 MW to be placed in service in the four consecutive years from 2003 to 2006. While tentatively identified as single-cycle combustion turbines, it is uncertain at this time whether any of the annual additions in generating capacity would be in the form of one 178-MW unit or two small units of less than 100 MW each. Furthermore, plant siting has not been determined; thus, any requirement to construct transmission lines along with the generating units is unknown. Although the primary fuel is assumed to be natural gas, sources of natural gas and water are unidentified at this time. Moreover, APS has not committed to building the generating units; therefore, basic parameters such as unit size, plant configuration, and ownership are preliminary and tentative.



## *Western Systems Coordinating Council*

EXISTING GENERATION  
AND  
SIGNIFICANT ADDITIONS AND CHANGES  
TO SYSTEM FACILITIES  
1997 - 2007

Data as of  
January 1, 1998

Prepared by  
Loads and Resources Subcommittee  
Data Collection Task Force  
WSCC Technical Staff

ISSUED  
APRIL 1998

WESTERN SYSTEMS COORDINATING COUNCIL  
SUMMARY OF GENERATION ADDITIONS AND CHANGES  
TABULATION BASED ON LOCATION OF UTILITY OPERATING THE GENERATION  
ARIZONA-NEW MEXICO-SO. NEVADA POWER AREA

(SUMMER CAPABILITY - MW)

GENERATION TYPE	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	10-YR. PERIOD	PERCENT OF TOTAL
HYDRO CONVENTIONAL	0	0	0	0	0	0	0	0	0	0	0	0.0%
HYDRO PUMPED STORAGE	0	0	0	0	0	0	0	0	0	0	0	0.0%
STEAM - COAL	0	0	0	0	0	0	0	0	0	0	0	0.0%
STEAM - OIL	0	0	0	0	0	0	0	0	0	0	0	0.0%
STEAM - GAS	0	0	0	0	0	0	0	0	0	0	0	0.0%
NUCLEAR	0	0	0	0	0	0	0	0	0	0	0	0.0%
COMBUSTION TURBINE	0	76	0	86	153	239	-158	276	397	424	1493	62.5%
COMBINED CYCLE	0	0	195	0	0	0	450	214	0	0	859	36.0%
GEOTHERMAL	0	0	0	0	0	0	0	0	0	0	0	0.0%
INTERNAL COMBUSTION	0	0	0	0	0	0	0	0	0	0	0	0.0%
COGENERATION	1	4	5	5	4	3	2	1	1	0	26	1.1%
OTHER	1	1	7	0	0	0	0	0	0	0	9	0.4%
TOTAL	2	81	207	91	157	242	294	491	398	424	2387	100.0%

WESTERN SYSTEMS COORDINATING COUNCIL  
SUMMARY OF GENERATION ADDITIONS AND CHANGES  
ARIZONA-NEW MEXICO-SO. NEVADA POWER AREA

ORG.	PLANT NAME / UNIT NO. / LOCATION	UNIT TYPE	NET CAPABILITY		PRIMARY FUEL		ALT. FUEL TYPE	COMMERCIAL OPERATION DATE		S O		COMMENTS
			SUMMER	WINTER	FUEL TYPE	DELIV. METHOD		ORGNL	NEW DATE	T	W	
APS	Palo Verde 1, Wintersburg AZ	NP	16	16	UR				1-97	J	U	Unit uprated
APS	Palo Verde 2, Wintersburg AZ	NP	16	16	UR				1-97	J	U	Unit uprated
IFP	Springerville 1, Apache Cnty AZ	ST	40	40	SUB	RR	NONE		1-97	U	U	Unit uprated 40MW
IFP	Springerville 2, Apache Cnty AZ	ST	40	40	SUB	RR	NONE		1-97	U	U	Unit uprated 40MW
APS	Palo Verde 3, Wintersburg AZ	NP	16	16	UR				4-97	U	U	Unit uprated
APS	Solar, AZ	PV	1	0	SUM			6-97	6-97	J	U	Distributed small units
APS	Generic Cogen 1, AZ	CG	1	1	NA			1-02	1-98	I	N	Independent power producer
APS	Solar, AZ	PV	1	1	SUM			1-98	3-98	V	U	Distributed small units
APS	Generic Cogen 2, AZ	CG	4	4	NA			1-03	1-99	I	N	Independent power producer
APS	Solar, AZ	PV	1	1	SUM			1-99	6-99	P	U	Distributed small units
APS	Mohave GT 1, Kingman AZ	GT	76	84	NG	PL	NONE	3-99	6-99	U	U	Built, owned and operated by APS. Output sold to CUC
APS	Generic Cogen 3, AZ	CG	5	5	NA			1-04	1-00	I	N	Independent power producer
APS	Solar, AZ	PV	7	6	SUM			1-00	1-00	P	U	Distributed small units
IFP	Santa Teresa CC 1, Dona Ana NM	CS	195	212	NG	PL	NONE	5-00	5-00	OT	N	Independent power producer
APS	Generic Cogen 4, AZ	CG	5	5	NA			1-01	1-01	I	N	Developer: Destec Energy
IFP	North Loop 5, Marana AZ	GT	86	86	NG	PL	NONE	6-00	6-01	L	U	Independent power producer
APS	Generic Cogen 5, AZ	CG	4	4	NA			1-02	1-02	I	N	To be converted to CC
NEVP	Allen GT2, Clark County NV	GT	153	153	NG	PL	F02	6-02	6-02	P	U	operation June 2004
APS	Generic Cogen 6, AZ	CG	3	3	NA			1-03	1-03	I	N	Independent power producer
IFP	North Loop 6, Marana AZ	GT	86	86	NG	PL	NONE	6-03	6-03	L	U	operation June 2004
NEVP	Allen GT3, Clark County NV	GT	153	153	NG	PL	F02	6-03	6-03	P	U	To be converted to CC
APS	Generic Cogen 7, AZ	CG	2	2	NA			1-04	1-04	I	N	operation June 2004
APS	Generic GT1, AZ	GT	148	178	NG	PL	F02	6-00	6-04	P	U	Independent power producer
NEVP	Allen GT2, Clark County NV	GT	-153	-153	NG	PL	F02	6-04	6-04	P	U	One 178MW unit
NEVP	Allen GT3, Clark County NV	GT	-153	-153	NG	PL	F02	6-04	6-04	RP	U	Converted to CC operation
NEVP	Allen CC1A, Clark County NV	CT	153	153	NG	PL	F02	6-04	6-04	RP	U	Converted to CC operation
NEVP	Allen CC1B, Clark County NV	CT	153	153	NG	PL	F02	6-04	6-04	RP	U	Converted from GT operation
NEVP	Allen CC1C, Clark County NV	CW	144	144	WH			6-04	6-04	RP	U	Converted from GT operation
APS	Generic Cogen 8, AZ	CG	1	1	NA			1-05	1-05	I	N	Independent power producer
APS	Generic GT2, AZ	GT	148	178	NG	PL	F02	6-01	6-05	P	U	One 178MW unit
APS	Unidentified 1, Pima County AZ	GT	128	128	NG	PL	F02	6-05	6-05	L	U	
IFP	Generic CC 1, Pima County AZ	CC	214	214	NG	PL	NONE	6-05	6-05	P	U	
IFP	Turbine 1,	GT	121	121	NG	PL	F02	1-06	1-06	P	U	Location not determined
APS	Generic Cogen 9, AZ	CG	1	1	NA			1-02	1-06	I	N	Independent power producer
APS	Generic GT3, AZ	GT	148	178	NG	PL	F02	6-06	6-06	P	U	One 178MW unit
APS	Unidentified 2, Pima County AZ	GT	128	128	NG	PL	F02	6-06	6-06	L	U	
APS	Generic GT4, AZ	GT	148	178	NG	PL	F02	6-07	6-07	P	U	One 178MW unit
APS	Generic GT5, AZ	GT	148	178	NG	PL	F02	6-07	6-07	P	U	One 178MW unit

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**news release****(9/16/98)**Contact: Dan McCarthy, (610) 774-5758**PP&L Global Plans to Build Arizona Power Plant**

ALLENTOWN, Pa.—PP&L Global, Inc., a subsidiary of PP&L Resources, Inc. (NYSE: PPL), plans to build a gas-fired power plant near Kingman, Ariz., with nominal base load capacity of 520 megawatts and a maximum output capability of 650 megawatts.

Robert D. Fagan, president of PP&L Global, said the proposed power plant, which is known as the Griffith Energy Project, is an excellent opportunity for the company. PP&L Global, which is headquartered in Fairfax, Va., has \$635 million in investments and commitments around the world.

"As the generation of electricity is deregulated in the United States, PP&L Global is seeking to develop and acquire power plants in key areas of the country," said Fagan. "The Griffith Energy Project site is an excellent location, in a region with significant growth in demand for electricity. In addition, the project should improve electricity transmission capability in the Kingman and Lake Havasu City region."

The Arizona Corporation Commission's Siting Committee on Monday (9/14) gave unanimous approval to PP&L Global's plans for the facility. The committee's approval was required for the project to move forward.

"We are very pleased with the expeditious action of the Siting Committee, which will allow us to proceed with our project work without delay," said Fagan. "The local support that we have been receiving from the Mohave County Economic Development Authority and the leaders of Mohave County also has been instrumental in PP&L Global pursuing this project. Work on the environmental impact study and air-quality permits are moving forward rapidly."

Fagan said PP&L Global is working with the Western Area Power Administration on interconnection, construction and services agreements for the electrical interconnection to Western's regional transmission system. The company also is negotiating with a construction contractor to build the facility.

NP Energy, the Louisville, Ky.-based energy marketing company owned 50 percent by National Power, plc, has agreed to purchase between 240 and 520 megawatts of the electricity produced by the facility, Fagan said. NP Energy, which is a major wholesale marketer in the Western United States, then will market the electricity through the region.

PP&L Global has formed an operating subsidiary, Griffith Energy LLC, to oversee construction of the project and to operate and maintain the power plant. When complete, the plant is expected to employ about 25 people.

Kingman is located near Arizona's border with Nevada, about 50 miles south of Lake Mead.

PP&L Global, in partnership with Stone & Webster, also is in negotiations to build a natural gas-fired power plant in the town of Wallingford, Conn.

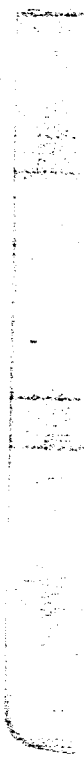
The Griffith Energy and Wallingford projects would mark PP&L Global's first ventures in the United States. PP&L Global has ownership interests in, and participates in the management of, companies in the United Kingdom, Chile, El Salvador, Peru, Argentina and Brazil, which together serve about 3 million electric distribution customers. In addition, PP&L Global owns interests in electric generation facilities in Spain, Portugal, Bolivia and Peru.

PP&L Resources, with headquarters in Allentown, Pa., also is the parent company of PP&L, Inc. which provides electricity delivery service to 1.2 million homes and businesses in Pennsylvania; generates electricity; sells retail electricity throughout Pennsylvania through its PP&L EnergyPlus Co.; and markets or trades wholesale energy to 26 states and Canada through its Energy Marketing Center.

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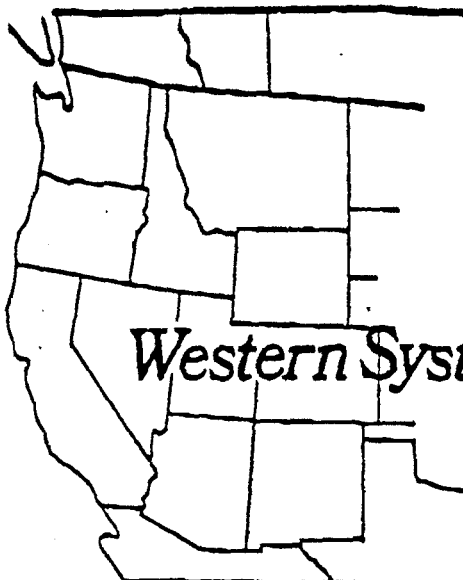
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Attachment 4

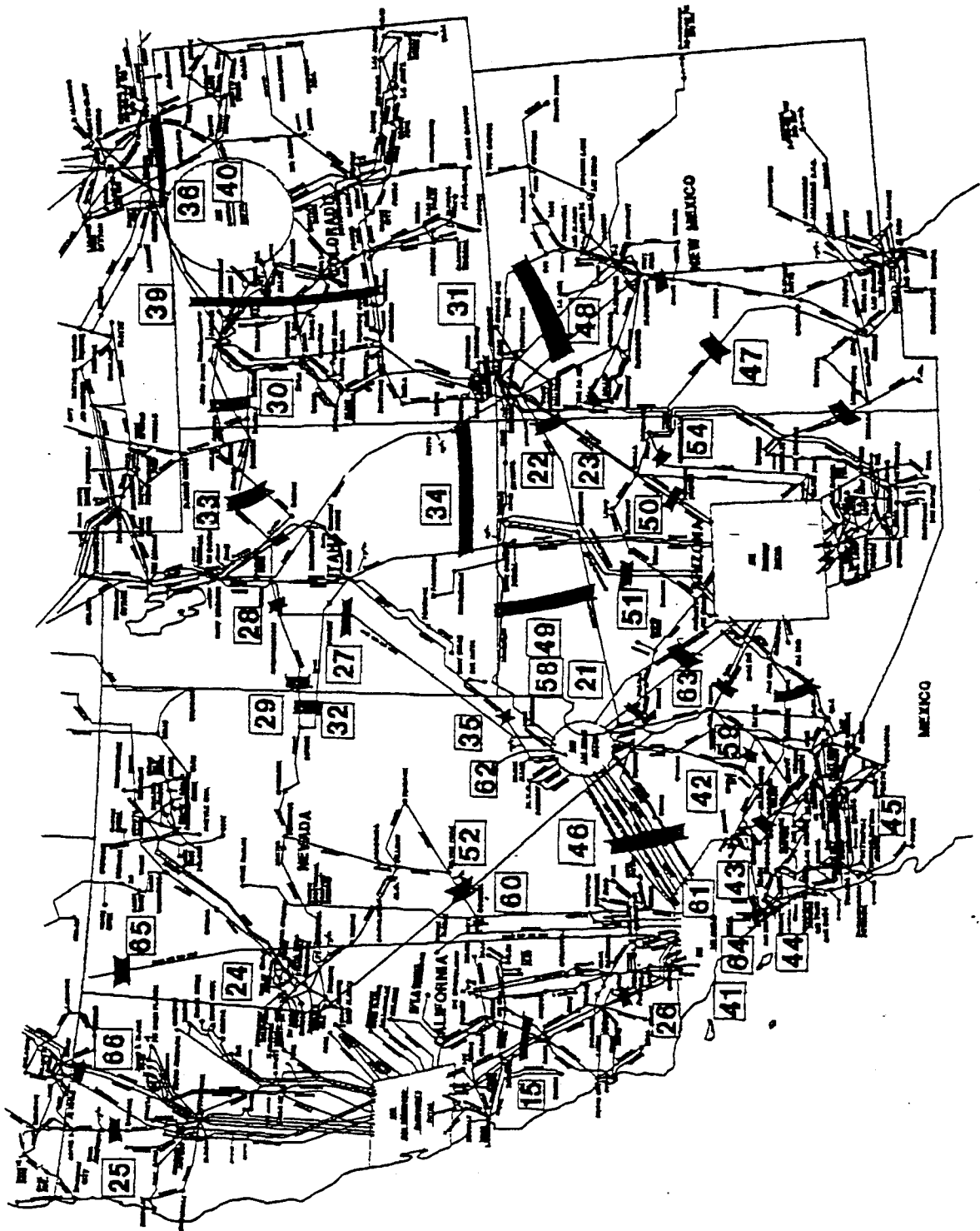
## *Western Systems Coordinating Council*

### WSCC 1998 PATH RATING CATALOG

February 1998

Prepared By:  
TECHNICAL STUDIES SUBCOMMITTEE

# WSSC Transfer Paths



# **Western Systems Coordinating Council**

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**May 1996**

## **Ten-Year Coordinated Plan Summary 1996 - 2005**

# Transmission

*The member systems' transmission facilities are planned in accordance with the "WSCC Reliability Criteria for Transmission System Planning," which establishes performance levels intended to limit the adverse effects of each member system's operation on others and recommends that each member system provide sufficient transmission capability to serve its customers, to accommodate planned interarea power transfers, and to meet its transmission obligations to others.*

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Information regarding the existing interconnected bulk power transmission system and the significant transmission facilities planned through the next ten years is compiled annually by the Council and provides the basis for this section.

As of January 1, 1996, the WSCC interconnected bulk power system was comprised of 112,798 circuit miles of transmission. No significant additions occurred during 1995 to the interconnected bulk power system. Figure 14 and Table 42 categorize existing transmission for the total WSCC region by voltage class and indicate that approximately 58 percent of the existing bulk power transmission is operated at a voltage class of 230 kV or above.

Figure 15 and Table 43 present information regarding the significant transmission additions planned for the 1996-2005 period. The planned transmission additions are categorized by voltage class, and the corresponding circuit miles are

summarized for each of the four WSCC areas. Significant transmission additions include interconnections to the system from major generation sources, interconnections between control areas, and transmission lines important to interconnected system operation. The total net transmission circuit miles (3,184) planned for the 1996-2005 period represent a 2.8 percent increase over the existing circuit miles as of January 1, 1996. Approximately 81 percent of the significant net circuit mile additions planned are of the 345 kV class or higher.

Ten-year projected transmission additions in the 500 kV AC voltage category for the 1996-2005 period have decreased by 982 circuit miles compared to the projections made last year. This reduction is due to: the cancellation of the Devers-Palo Verde #2 500 kV line between Arizona and southern California and the Nicola-Meridian 500 kV line #2 in British Columbia; and the delay beyond

2005 of the Delta-Harry Allen 500 kV line between Utah and southern Nevada, the Delta-Robinson Summit 500 kV line between Utah and central Nevada and the Harry Allen-Marketplace 500 kV line #2 in southern Nevada. Additions in the 345 kV AC voltage category have decreased by 726 circuit miles compared to the projections made last year. This reduction is due to the cancellation of the Terminal-Falcon 345 kV line between Utah and northern Nevada, the Dry Fork Energy Project-Osage 345 kV line in northern Wyoming, the Dry Fork Energy Project-Colstrip 345 kV line between northern Wyoming and southern Montana, and the Coyote-Norton 345 kV line in New Mexico. Additions in the 230 kV AC voltage category have decreased by 677 circuit miles compared to the projections made last year. This reduction is due to the cancellation of the Bell-Selkirk 230 kV line between southern British Columbia and eastern Washington, the Dry Fork Energy Project-Yellowtail 230 kV line between northern Wyoming and southern Montana, and the El Centro-Coachella 230 kV line in southern California.

Significant transmission additions reported for the next ten years include 670 miles of 230 kV transmission lines, 1,038 miles of 345 kV, and 1,529 miles of 500 kV. Some of the noteworthy additions in each voltage category are highlighted on the map on the following page.

A copy of the map titled "WSCC Planned Facilities Through 2005 and Possible Transmission Beyond This Period" is included at the end of this report. The existing network as of January 1, 1996, is illustrated in black and significant facility additions planned for the

1996-2005 period are portrayed in

color. Parenthetical numbers on the map indicate system ownership as defined in the legend, and anticipated in-service dates of planned transmission are also generally indicated.

The planned transmission additions for the WSCC region through the year 2005 reflect a continuing interest in the development and strengthening of interconnections to enhance system reliability; to transfer hydro, nuclear, and coal-fired energy to gas/oil-burning areas; to increase the capability for economy energy transfers; and to enable diversity in exchanging power between areas with different seasonal peak demand and energy requirements.

Transmission additions in the 500 kV category represent 48 percent of the planned significant additions. By the year 2005, the 500 kV transmission system mileage will have increased by approximately 10 percent.

To help in mitigating major unscheduled flow problems, several utilities have cooperated in the installation of phase-shifting transformers in the southern Utah/Colorado/Nevada transmission system. Phase-shifting transformers were installed in the southwestern Colorado-northwestern New Mexico lines during 1989, and additional phase-shifting transformers were installed in the lines emanating to the south from Utah during 1991.

The installation of DC links in Canada, New Mexico, Nebraska, and southeastern Montana permit the transfer of electricity between WSCC and two adjacent councils: Southwest Power Pool and Mid-Continent Area Power Pool.

In effect, the WSCC system

is being developed to ensure the efficient and economical use of resources and at the same time ensure adequacy, reliability, and environmental compatibility.

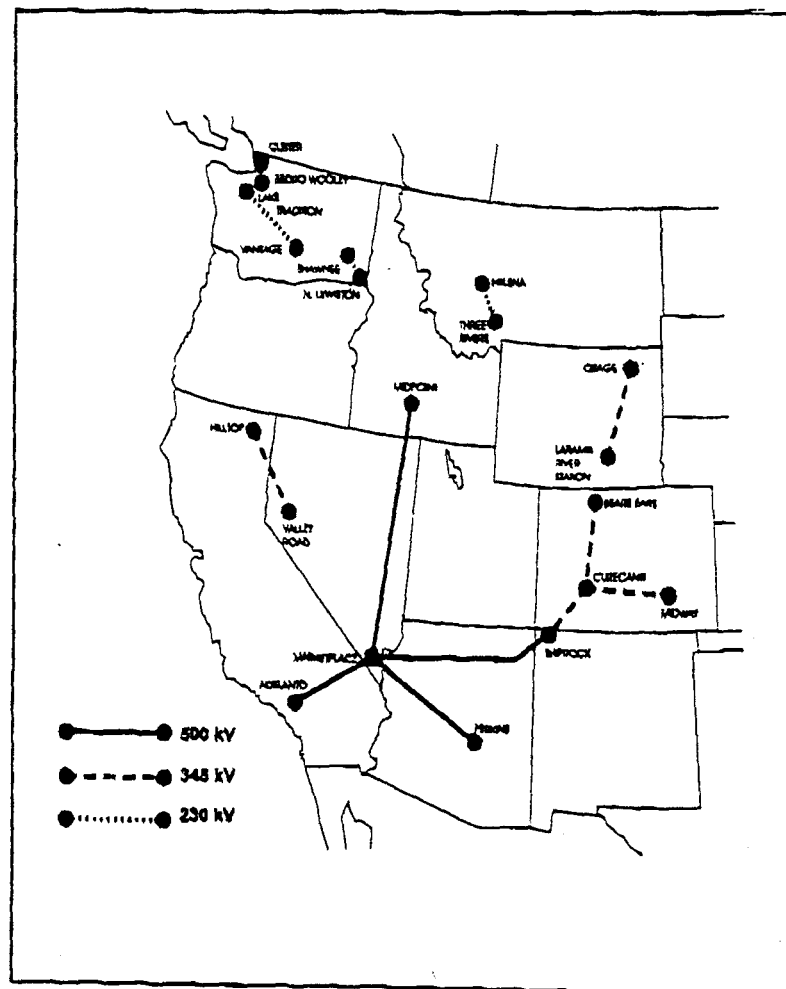
Figures 16 and 17 illustrate WSCC nonsimultaneous transfer capabilities for 1996 and 2001 respectively. These transfer capabilities represent the total capability of the various interconnections of the existing system and the planned 2001 system. It should be recognized that the transfer capability of an interconnection is not a single value as it is dependent upon system conditions, and the simultaneous import capability of a given area may be less than the sum of the individual

interconnection capabilities. Each

transfer capability depicted has been determined for a specific system condition.

Transfer capabilities between the WSCC areas are generally adequate to accommodate the existing and anticipated firm power schedules. However, there are limitations that persist in accommodating all desired economy/surplus power transfers.

In some instances, dependence has been placed on complex remedial measures to enable increased power transfer levels for use of the region's most cost-effective resources. The reliability and security of these remedial action schemes are reviewed periodically and updated when necessary.



Transmission Additions 1996-2005



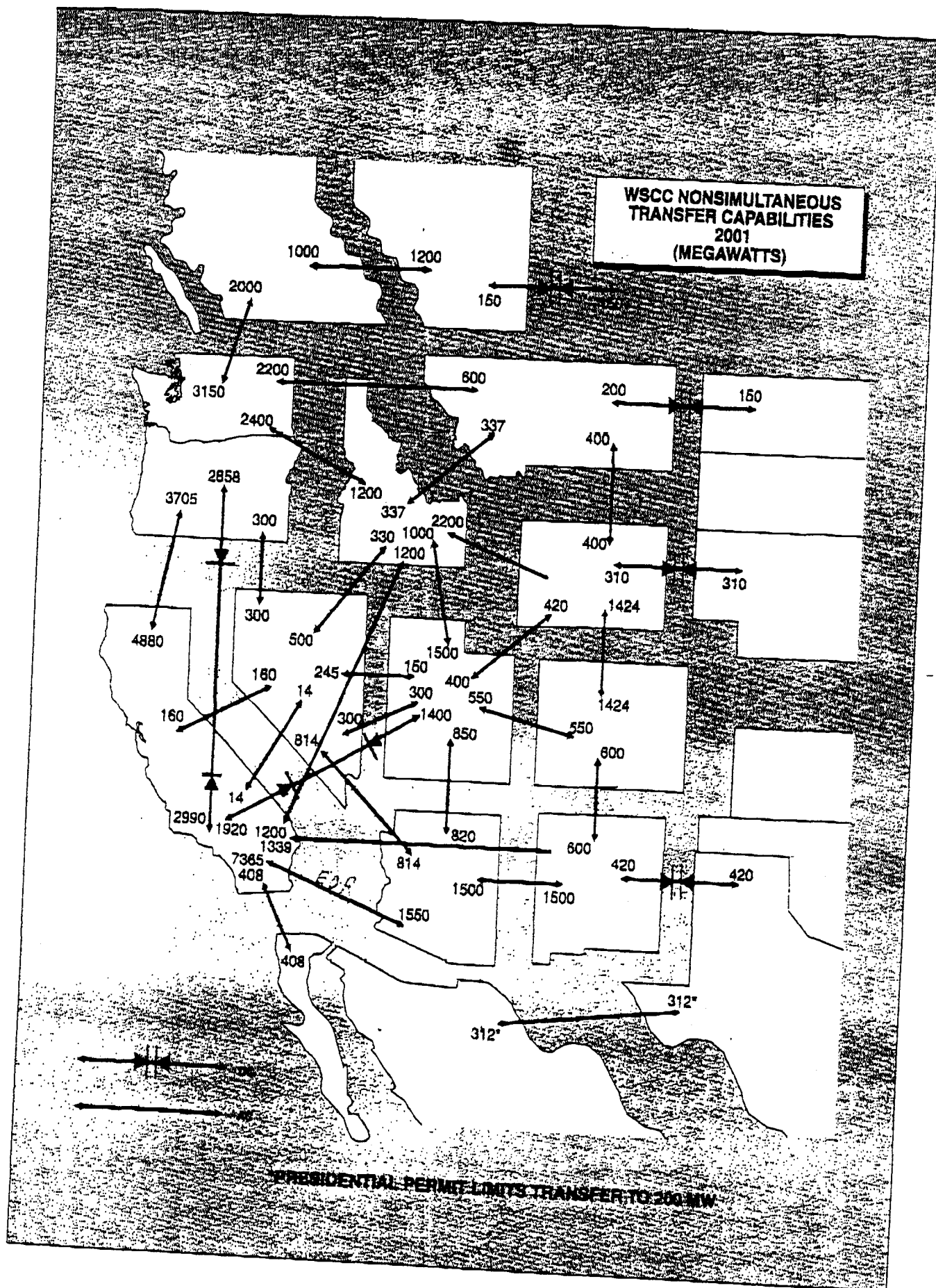


Figure 17